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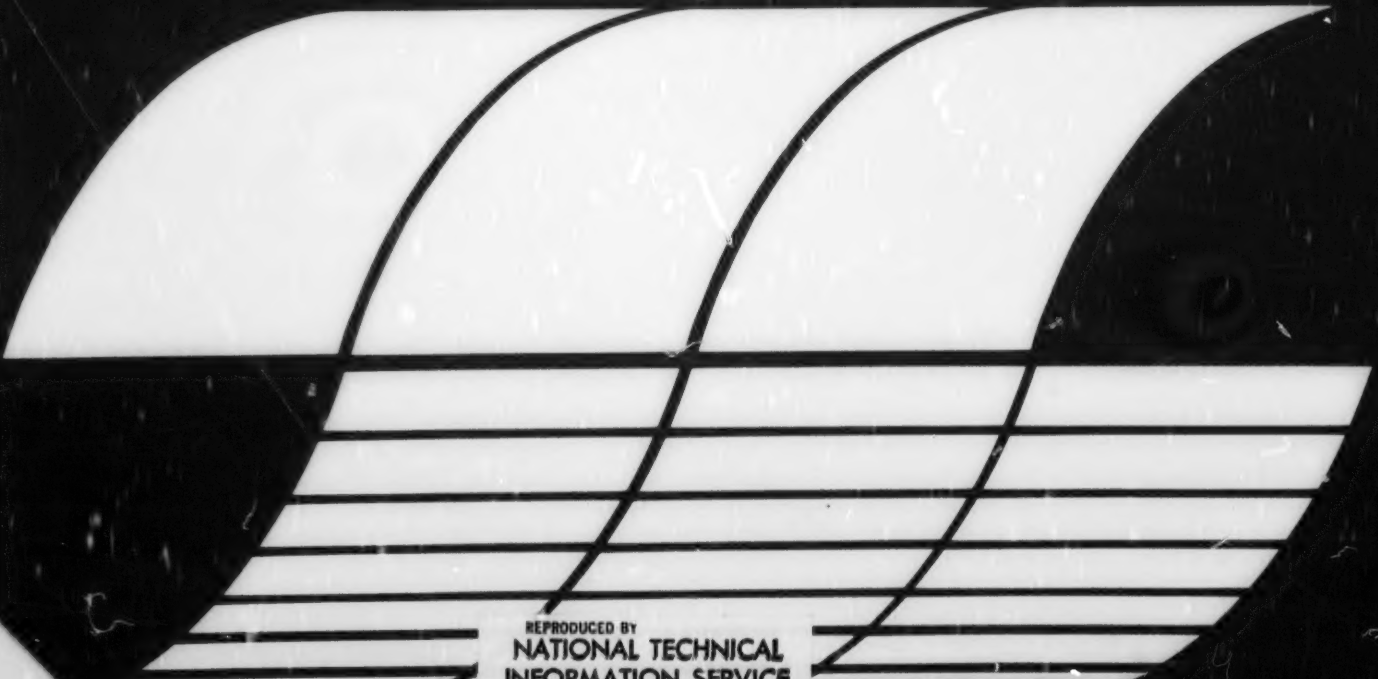

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Recommendations are presented for monitoring and predictive technology for the coal conversion and oil shale industries. The recommendations are based upon a literature survey of the emissions and potential impacts of these industries. Descriptions of the technologies are included.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Coal Mining	Monitoring	07C
Coal Gasification	Coal Slurry Pipeline	13B,H
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FOREWORD

Protection of the environment requires effective regulatory actions which are based on sound technical and scientific information. This information must include the quantitative description and linking of pollutant sources, transport mechanisms, interactions, and resulting effects on man and his environment. Because of the complexities involved, assessment of specific pollutants in the environment requires a total systems approach which transcends the media of air, water, and land. The Environmental Monitoring and Support Laboratory-Las Vegas contributes to the formation and enhancement of a sound integrated monitoring data base through multidisciplinary, multimedia programs designed to:

- develop and optimize systems and strategies for monitoring pollutants and their impact on the environment
- demonstrate new monitoring systems and technologies by applying them to fulfill special monitoring needs of the Agency's operating programs

This report describes existing and developing technologies associated with the extraction and processing of coal and oil shale, identifies the pollutants likely to be produced by these technologies, discusses the potential impacts of these emissions, and recommends monitoring systems research and development to help alleviate the impacts. The report is intended to assist organizations responsible for promulgating monitoring research and development programs relevant to coal and oil shale resource development. If additional information is desired, contact Mr. Robert K. Oser, Office of Program Management and Support, Environmental Monitoring and Support Laboratory in Las Vegas, Nevada 89114.

George B. Morgan

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SECTION I

INTRODUCTION

The utilization of the vast coal and oil shale resources of the United States offers the potential for supplementing the dwindling supplies of petroleum and natural gas. Concurrent with increased emphasis on developing domestic energy resources is concern for improving the control of air and water pollution.

Considerable effort is being expended to develop methods that will convert coal and oil shale into clean, convenient fuels. If successful, these conversion processes will provide new fuels that will help to meet energy demands and, at the same time, be environmentally acceptable. However, these conversion processes may themselves present sizeable pollution problems. Therefore, it is important to determine the environmental consequences of large-scale coal and oil shale utilization. Monitoring and predictive technology are necessary aspects of such a determination.

The objective of this study was to elucidate the important needs for the measurement and prediction of the impacts of coal and oil shale extraction, processing, and conversion on air quality, water quality, and land use. The measurement needs are limited to ambient monitoring techniques. Accurate ambient monitoring helps to establish causes of environmental impacts and to determine the success of pollution control procedures. Ambient monitoring is also useful in assessing and modifying modeling techniques.

SECTION II

SUMMARY

This report presents the results of a study whose objective was to identify important monitoring and predictive technology needs relative to the conversion of coal to clean fuels and to the production of oil from oil shale. The extraction, processing, and conversion of these fuels were examined in considerable detail with regard to their impacts on air quality, water quality, and land use. The transportation of coal by a slurry pipeline was also included in the study.

The work performed in this study divides into the following three areas: (1) the identification of technologies, (2) the identification of environmental impacts, and (3) the identification of monitoring and predictive technology needs.

The first phase of the study involved the identification of promising technologies for the extraction, processing, and conversion of coal and oil shale. A review of the present technological position (state-of-the-art) of each of these technologies is provided in Section V. Discussions are provided for coal extraction, coal slurry pipelines, coal cleaning, coal gasification, coal liquefaction, oil shale extraction, oil shale retorting, and shale oil upgrading. With respect to coal, the emphasis of this report is on the processes that convert coal into clean fuels. Coal extraction and cleaning processes were included because the huge demand for coal in the future will greatly increase their environmental impacts. Coal slurry pipelines were included in this report because they are a promising new technological development. Coal combustion and coal-product combustion processes are not included in this study.

Section VI of the report discusses emissions and other impacts for each of the technologies described in Section V. For each technology, data are provided on air emissions, water emissions, thermal emissions (water only), solid wastes, land use, and water requirements. In order to achieve a common basis for comparison, it is assumed that the amount of fuel handled per day is equivalent to 10^{12} British thermal units.* Air emissions are given in pounds per day for the criteria pollutants. For coal gasification and liquefaction, information on emissions of trace materials such as ammonia, hydrogen cyanide, phenols, benzene, oils and tars, trace metals, and trace organics is provided. The pollution potential of coal gasification and liquefaction is discussed in both general terms and with respect to specific processes. The known and potential environmental emissions of specific chemical species are identified and quantified to the extent possible from available literature.

The last half of Section VI discusses potential impacts from the emissions. Due to a lack of full-scale coal conversion plants or oil shale plants, no data are available on specific impacts; however, correlations are drawn with other industries, and specific cases are discussed. The importance of exposure pathways and the dependence of the pathways on the design and location of the individual facilities are discussed first. This is followed by discussions of the potential impacts of sulfur dioxide, sulfates, particulates, hydrogen sulfide, hydrogen cyanide, and ammonia. It is generally concluded that only the sulfates and particulates are likely to present problems.

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*English units are commonly used for the processes discussed in this report. For conversion of English units to modern metric units, see Appendix A.

Next, potential impacts of trace metals are discussed in some detail, but information on impacts is insufficient to permit definite conclusions to be drawn. Some suggested studies are described which will help determine whether trace metals are a problem and to what extent they should be monitored.

Trace organics and their potential impact are discussed next. Again, a lack of carefully-studied operating systems prevents a knowledge of the exact species emitted and a historical record of their impacts. The known impacts of some specific organic compounds are discussed, and recommendations for studies which will shed light on long-term monitoring needs are presented.

The information in Section VI concerning the potential environmental impacts of coal and oil shale processes provides the basis for identifying monitoring and predictive technology needs. Section IV lists recommendations for improving monitoring and predictive technology with respect to the coal conversion and oil shale industries. Successful implementation of these recommendations will, however, be applicable in many areas other than just the two developing industries. Both monitoring and predictive technology needs are divided into air and water categories. Two particularly important items are the need to develop monitoring techniques for continuously measuring low concentration species such as trace elements and trace organics in the ambient environment and the need to develop accurate techniques for monitoring the quality of ground water. Improved particulate monitors and remote sensing instrumentation are also areas that deserve research and development.

SECTION III

CONCLUSIONS

Significant environmental impacts could result if proper pollution control techniques are not provided during the development of the nation's coal and oil shale resources. Both coal conversion and oil shale industries require the processing of huge amounts of raw material. For the two industries, many species are likely to be emitted for which no regulations presently exist. Some of these may be hazardous as emitted, or may subsequently undergo some transformation which renders them hazardous. Processes for converting fossil fuels into clean fuels could themselves become major sources of pollution. To avoid significant environmental impacts, careful assessment of these technologies is necessary.

The refinement and development of monitoring and predictive technology are essential elements of pollution control to avert major environmental impacts from coal and oil shale industries. Section IV discusses monitoring and predictive technology needs.

The coal and oil shale industries could be significant contributors to low-level pollution by the emission of trace elements and trace organics. Improved monitoring systems and research programs are necessary to cope with the long-term effects of low ambient concentrations of pollutants.

Trace metals and trace organics occur at low concentrations; thus, long sampling periods followed by sample preparation and laboratory analysis has typically been the only measurement technique. Rapid feedback, field measurement techniques are needed for trace organics, both in air and in water.

The above comments about trace metals and trace organics apply particularly to emissions from coal conversion facilities, but also apply to many other industries and problems. If additional information could be obtained regarding the role of various hydrocarbon species or classes of hydrocarbon species in photochemical smog, more effective ambient air hydrocarbon standards could be developed. This information would allow the expenditures for controls to be channeled to the most effective areas.

Additional data are also needed regarding the fate of pollutants in the environment and their long-term effects on plant and animal life. This information would permit the most effective standards to be determined, and would allow expenditures on control systems to be used most effectively.

After determining the variation in composition of waste streams using developing technologies, appropriate monitoring and modeling programs can be established.

The coal and oil shale industries are potentially large-scale industries with sizeable environmental impacts, but they are both in early stages of development which allow them to be responsive to pollution control techniques to effectively minimize these environmental impacts. Development of improved monitoring and modeling technology should occur simultaneously with and complement the development of new technologies.

SECTION IV

RECOMMENDATIONS FOR RESEARCH AND DEVELOPMENT

Regulations presently define the particular species for which monitoring is needed and also establish the standards for the monitoring. Averaging-time is an example of the way regulations affect monitoring. A one-hour standard is specified for ozone (O_3), while an annual standard is specified for nitrogen dioxide (NO_2). Measurement of ozone once during each hour for a year would provide little confidence that the maximum one-hour value actually was observed. Measurement of NO_2 once each hour, however, would provide an adequate statistical description of the NO_2 level for the one year period. Thus the need for a continuous analyzer is greater in the case of ozone than in the case of NO_2.

The specified concentration also influences monitoring needs. The standards for sulfur dioxide (SO_2) require sensing of levels of 30 parts per billion (ppb); however, sensing of levels of 9000 ppb is sufficient for carbon monoxide (CO). Sensitivity is thus much more important in the case of SO_2.

Research on monitoring methods must not await the defined need provided by regulations. To a greater extent, regulations are being defined by health effects studies, and once a clear cut need is established, there is not time for a lengthy research and development program to provide adequate monitoring methods. This work should anticipate or parallel the health effects studies. In fact, the studies themselves would be greatly expedited if they were not constrained by laborious and time-consuming manual collection and manual laboratory analyses of samples.

The case of ground water monitoring provides an example. Almost no regulations for monitoring of ground water currently exist. Over 90 percent of the nation's available water is ground water, and the fact that reclamation of a polluted aquifer ranges from difficult to impossible provides ample justification for development of monitoring techniques for ground water. The availability of such techniques would help shape any required regulations to protect this valuable resource.

In the case of coal conversion and oil shale industries, many species are likely to be emitted for which no regulations presently exist. Some of these may be hazardous as emitted, or may subsequently undergo some transformation which renders them hazardous.

The monitoring and predictive technology needs for the coal and oil shale industries will be discussed in the following paragraphs. These needs are divided into air and water monitoring categories.

A list of recommended research and development efforts is provided for each category, but special emphasis should be given to the following items:

> Automatic, continuous or semi-continuous field monitors are needed to provide detailed analyses of trace organics and trace elements under ambient conditions.

- Accurate techniques should be developed for monitoring the quality of ground water.
- Improved particulate analyzers are needed.
- Further development of instruments to make remote measurements of air or water quality would be invaluable.

These and other recommendations will be discussed in more detail below.

MONITORING NEEDS

Air Monitoring

In the monitoring instrumentation area, the greatest needs are for automatic, continuous or semi-continuous field monitors to provide a detailed analysis of trace organics and trace metals. In the case of the trace metals, it is important to be able to distinguish particular oxidation states and particular compounds.

Coal conversion and oil shale plants are potential emitters of hazardous trace metals and trace organics. These potential emissions could significantly contribute to low ambient concentrations of hazardous pollutants. Low-concentration, ambient pollution, presently a matter of great concern, is poorly understood. Improved monitoring systems are necessary to cope with the long-term effects of low concentrations of pollution. Because of the huge amounts of raw material needed for coal conversion and oil shale plants, large quantities of trace elements will be processed. The same is true for trace organics which are either contained in the original material or are formed by thermal treatment. The ability to monitor these species in the ambient environment is a necessary step toward insuring that pollution control procedures are working properly.

Analysis of trace metals generally is not done under field conditions or on a continuous basis, since present techniques require sample concentration procedures. Adequate monitoring of these species will require development of techniques which can be used under field conditions, which provide continuous or rapidly updated results, and which can distinguish oxidation states and preferably, particular compounds. A big difference between coal-using plants of today and future coal conversion facilities relates to the oxidation-reduction conditions. Presently, coal is burned in a largely oxidizing environment. Coal conversion processes provide a reducing environment, and species emitted from such processes are less likely to be stable in air than is presently the case for coal-burning facilities. In terms of monitoring, this means that a real-time, field analysis system is needed to adequately determine what species are found initially, and to monitor their transformations. Many trace elements are most hazardous in their lower oxidation states, the form in which they may be emitted from coal conversion facilities.

As with trace metals, trace organics occur at low concentrations; thus, long sampling periods followed by sample preparation and laboratory analysis has typically been the only measurement technique. Rapid-feedback field measurement techniques are needed to identify and quantify trace organics in air and in water.

The above comments about trace metals and trace organics apply particularly to emissions from coal conversion and oil shale facilities, but also apply to many other industries and problems. If additional information could be obtained regarding the role of various hydrocarbon species or classes of hydrocarbon species in photochemical smog, more realistic ambient air hydrocarbon standards could be developed. This would allow the expenditures for controls to be channeled to the most effective areas. The development of monitoring devices for trace elements and trace organics is, therefore, a necessary area of research.

Automated particulate analyzers which can measure short-term particulate averages are needed. Some beta particle detectors of this type are becoming available; however, they are almost prohibitively expensive as replacements for the High Volume Method samplers. A possible approach to this problem might be to separate the collection and analysis functions, i.e., to have one beta particle analyzer support many field collection devices. This will require that the collected samples be transportable without loss of the particulates. Particulate monitoring devices are also needed which classify the collected particulates according to size. Such particulate analyzers would be valuable in assessing the impacts of the huge extraction and material-handling problems associated with developing coal and oil shale resources.

There also is a real need for an air monitoring rationale, i.e., how many stations should be used, how should they be sited, should they be moved seasonally,etc. It is presently difficult to compare results from various networks due to uncertainties resulting from the network designs. The siting rationale must be flexible enough to allow for different monitoring goals. Most monitoring methods in use today are quite site-specific, i.e., they represent the air quality at a given point. Techniques are needed to characterize air quality over broader areas. When monitoring particulates at an open pit mine or hydrocarbons around a refinery, it is difficult to describe the air quality in general since moving the monitor a short distance may cause a significant change in the levels. A number of downwind plume measurements are needed for area sources and for cities so that meaningful comparisons can be made of air quality from year to year. These considerations are particularly important in the western United States where the major new sources of coal and oil shale are located. In many cases, the topography is extremely important in developing an air monitoring network.

Along similar lines, there is a real need for further development of instruments to make remote measurements of air or water quality. Even a very expensive device could be cost-effective if it could be used to obtain large area coverage rapidly. Remote sensing devices would be valuable for making measurements of pristine areas in the West where coal and oil shale development is proposed. These devices could help to rapidly establish baseline data for regions that are presently almost inaccessible.

Additional work is needed in techniques for collection and preservation of trace organics. In many cases, it is not known to what extent collected samples change as a result of the collection or preservation procedures. Over the short term, field collection and concentration of samples, followed by analysis in a laboratory, seems to present the best approach to monitoring of many trace organic species. This is a slow and expensive procedure, and uncertainties due to the sampling and preservation must be minimized.

Data are needed regarding the fate of pollutants in the environment and their long-term effects on plant and animal life. Such data would permit the most realistic standards to be determined and would allow expenditures on control systems to be made most effectively.

Better methods of tracing pollutants in the atmosphere are needed. With a wide number of easily detectable tracers, the contributions of many local sources to the air quality in an area could be determined and would allow the optimum control strategy to be developed. Tracers would also aid in studying the fate of pollutants in the environment.

Monitoring instruments for the criteria pollutants need improvement in their sensitivity. This would aid baseline studies in pristine areas and would allow better evaluation of the influence of species such as nitric oxide (NO) and nitrogen dioxide (NO_2) on formation of photochemical smog.

There is a constant need for improvement in calibration systems and the long-term stability of calibration standards. The drift rates, mean time between failure, and temperature sensitivity of most automated instruments need improvement.

Water Monitoring

It is assumed in this report that there will be little or no discharge of waste water to surface streams from coal conversion or oil shale plants. Most facilities being planned are based upon a zero discharge concept. Nevertheless, some effluents could still find their way to surface streams through ground water (springs), stormwater runoff, or accidental overflows or discharge.

There is considerable potential for contamination of ground water by both coal conversion and oil shale facilities, and the monitoring needs are greatest in this area. In-situ processes offer the greatest possibilities for direct ground water pollution. The massive amounts of waste solids in the coal and oil shale industries offer another source of contamination. The slag, char, and ash generated in coal conversion plants and the spent shale from retorting facilities probably will contain enriched amounts of trace elements. There is also the possibility that carcinogenic organic compounds may be present, as has been demonstrated for some types of spent shale. Leaching of trace elements or trace organics from these waste solids could contaminate ground water. Over ninety percent of the nation's available water is ground water; in many of the areas which will be most impacted by the development of coal and oil shale, the ground water is especially important because of the limited availability of surface water. A polluted aquifer is nearly impossible to reclaim.

There is a definite need for a rapid and accurate technique for determining from one well the direction and rate of ground water movement. This would aid in siting monitoring wells and in choosing locations for disposal sites.

Also needed is a technique to monitor the movement of trace metals and trace organics in solids in both saturated and unsaturated zones. There are indications that some soils will strongly absorb many trace metals; however, the capacity of a given volume of soil may be low, or some subsequent change in the soil environment might cause the metals to be displaced. Better sample collection devices and procedures are needed for ground water in both saturated and the unsaturated zones. In addition, better definition of well drilling and well completion procedures are needed for monitoring wells. In some cases, the monitoring well itself makes it almost impossible to obtain a representative ground water sample. An example is a well drilled with a bentonite drilling fluid. The bentonite becomes caked in the formation surrounding the well bore, and subsequently removes trace organics and trace metals from ground water flowing into the well bore.

The number of parameters which can be monitored continuously in both ground water and surface water must be increased. Specific ion electrodes represent the greatest advance in this area, but their long term stability needs improvement. Along these same lines, methods for automatic cleaning and calibration of water monitors need improvement. It would be desirable to utilize a blank prepared from the stream being monitored with only the monitored species removed. The effect of interferences would thus be eliminated during the calibration.

Other monitoring techniques for ground water, such as soil temperatures measurement, shallow earth resistivity measurement, and down-hole geophysical methods should be explored further to ascertain their applicability and limitations in defining flow and/or quality.

Similarly, the type of pollutants to be nationally monitored for a specific type of energy facility need to be defined. This effort must account for a range in reactivity likely to exist in the ground-water or surface-water influent. For example, the chloride anion is considered conservative and may be a good indicator of the extent of potential contamination, but more deleterious and insidious contaminants, such as trace elements, in the geohydrologic environment may be attenuated, i.e., retarded along the flow path of the influent water. Other constituents of the mixed geohydrologic fluid may show different amounts of attenuation, especially in various geologic settings. A monitoring program may be designed to consider the variable reactivity of different pollutants that are monitored to define the contamination enclave.

As was the case for air monitoring, there is a definite need for further development of instruments to make remote measurements of water quality.

A reliable, inexpensive method for monitoring or otherwise ascertaining the integrity of pond liners should be developed. Similarly, pre-treatment and operational procedures oriented toward maintaining the integrity of various liner types are desirable.

PREDICTIVE TECHNOLOGY NEEDS

Air Modeling

Broadly speaking, the fundamental limitations in the ability to predict pollutant transport and transformations in the atmosphere are imposed by an incomplete understanding of the chemical and photochemical kinetics associated with pollutant transformations and the so-called closure problem (TE-197) associated with characterizing atmospheric turbulence. It is recognized that recommendations have a subjective bias conditioned by prior experience in various areas. Moreover, there is a question of reconciling the relevance of an effort on a fundamental level with the pragmatic exigencies of solving air pollution problems. Finally, a large amount of effort is currently being expended in smog chamber studies, wind tunnel studies, modeling studies, full-scale atmospheric and monitoring studies.

Specific recommendations relating to improvements in current physicochemical grid models have recently been suggested (SE-105). These recommendations relate to development of a validated kinetic mechanism for characterizing ozone production in the presence of oxides of nitrogen (NO_x) and hydrocarbons. Additional recommendations (SE-105) are made to improve the theoretical and numerical features of models used for simulating reactive transport in an urban area.

Apart from the recommendations in the references cited, it is suggested that additional validation studies be performed to assess the accuracy of grid models under controlled conditions.

A recent evaluation (NA-237) of various models indicates that models previously regarded as quite accurate are less accurate in predicting spatial trends than in predicting temporal trends previously evaluated. It should be noted that the evaluation was based on predictions of CO, an inert pollutant, for which uncertainties in kinetic mechanisms do not arise.

Models are available to treat certain aspects of transport in rugged terrain. A complete characterization is unavailable, however, due to uncertainties concerning the terrain-induced turbulence. Although a number of studies concerning terrain-induced effects have been performed, definitive results are difficult to obtain. Because of the importance of environmental considerations in development of western energy resource sites, many of which are located in complex terrain, a program designed to address the problem of terrain-induced effects on pollutant transport is considered to be of paramount importance.

Micro-meteorological modeling is needed for box canyons which have been proposed as the depositories for spent shale.

Transport of pollutants emitted from low level, relatively cold sources (as opposed to tall hot stacks) needs to be better understood, and better models need to be developed. Examples of low-lying sources are fugitive hydrocarbon losses from refineries, coal conversion plants, and similar facilities.

An important issue in relation to environmental impact studies is whether postulated kinetic mechanisms can adequately describe transformations inside a plume issuing from a point source. An important unknown is the degree of mixing and dispersion which occurs in the plume and the degree to which turbulence fluctuations affect the chemical reaction rates. There are indications that turbulent fluctuations can influence the rates of reaction (ES-009), although such influences are not considered in present models. Tracer studies to characterize the stack-induced turbulence would be useful in this regard.

Current emphasis in reactive transport modeling has been placed primarily on the problem of photochemical smog production. The problem of specifying the fate of reactive species has received little attention. An adequate characterization of expected concentration of these species requires the development of a rate mechanism which accounts for their sources, transformations, and loss mechanisms. Accurate modeling of area-wide air quality requires a knowledge of the sources, both natural and man-made, and the mechanisms for pollutant removal from the atmosphere. Natural sources of the various pollutants and the loss mechanisms for pollutants in general are probably the most neglected areas of air pollution research.

Long-range transport of pollutants is not well understood. Long-range is defined to be distance greater than several tens of miles or transport times greater than a few hours.

Related to the above is the area of atmospheric aerosol formation and sulfate and nitrate problems in particular. The formation, transport, and loss mechanisms for these species are not fully understood, and meaningful modeling is almost impossible.

Long-term degradation of visibility is an apparent problem and should be investigated.

Techniques for the inclusion of terrain effects in dispersion models should be improved. This applies to both advection and diffusion.

Better techniques for the inclusion of time varying meteorological fields in dispersion models are needed.

Water Modeling

The existence and temperature dependence (over a significant range, e.g., 0-100°C) of important ion pairs and higher complexes in natural water systems are needed for implementing geochemical solution-dissolution models.

A reliable guide to the calculation or determination of dispersion coefficients for ground water is needed.

A methodology and identification of important parameters must be made to aid in the development of low-flow frequency analyses of surface water in ungaged locations.

More definitive techniques must be developed to measure and model the existence and effect of nonpoint-source pollution parameters.

The numerical simulation of flow in the unsaturated zone is necessary to adequately model ground water quality on a basin-wide scale. Similarly changes in the quality of water moving through the unsaturated zone are of extreme interest as this zone is where most water quality changes occur.

Flow in layered, anisotropic strata of different permeabilities must be modeled so that a comparison with the existing technique of assuming average conditions and homogeneous and isotropic media can be made to determine the reliability and applicability of these assumptions.

Improved finite-difference algorithms for nonlinear equations should be developed to improve three-dimensional matrix techniques.

Better data and prediction of thermal stratification are needed.

Procedures for treating sub-grid scale phenomena in three dimensional matrix problems needs development.

More emphasis should be placed on the practical validation of predictive numerical models. Many models are in use without validation of the available options.

Most models of ground-water flow and quality consider only the hydraulic head as the driving force. Other potentials (osmotic-pressure, adsorption, thermal, chemical) need to be evaluated to determine under what circumstances they are significant in ground-water flow.

The geochemical environment that causes desorption of previously sorbed contaminants for various wastes from energy facilities needs to be defined, and the possiblity that such environments may be achieved during or after waste disposal should be assessed. Desorption can result in the release to ground water of so-called "slugs" of relatively concentrated, toxic constituents to ground waters. The fate of such slugs also should be investigated.

SECTION V.

TECHNOLOGY DESCRIPTIONS

COAL EXTRACTION

The two types of mining operations are underground and surface mining. Underground mining techniques are conventional room and pillar, continuous room and pillar, and longwall. Surface mining techniques are open-pit mining, strip mining, and auger mining. Open-pit mining, commonly used in the metals industry to mine deep, very thick deposits of ore, is not used to mine coal. The 1973 production rates for the various mining methods are given in TABLE 1.

TABLE 1. ESTIMATED BITUMINOUS AND LIGNITE PRODUCTION FOR 1973 (SOURCE: NI-036)

Mining Operation	Millions of Tons	Percent of Total
Underground:		
Continuous room and pillar	181.0	30.7
Conventional room and pillar	102.0	17.3
Longwall	8.0	1.3
Surface:		
Strip mining	283.0	48.0
Auger mining	16.0	2.7
Total	590.0	100.0

Underground gasification techniques can also be considered potential methods of extracting coal energy. Underground coal gasification is in the experimental phase of development.

Underground Mining

Underground mining applies to mining methods involving the construction of a tunnel or shaft to access an underground resource deposit. Once this access shaft is established, mining of the deposit can be attempted by any one of several means. From 1973 statistics, continuous room and pillar mining accounted for 62.3 percent of all underground mined coal, conventional room and pillar 35.1 percent, and longwall 2.6 percent (NI-036).

The development of all three types of underground mines follows the same procedures. First, at least three main accesses or shafts are strategically driven to the coal bed. Three types of access, (1) drift, (2) slope, and (3) shaft, are shown in Figure 1. Once the main accesses have been constructed, two parallel main entries into the coal bed are driven in the direction of the mining operation. Panel entries are driven from the main entries to divide the coal seam into blocks. Finally, from the panel entries, butt entries are made into the coal seam resulting in the formation of "pillars" which support the roof. Butt entries are the headings made into the panels for the systematic removal of the coal. This is room and pillar or advance mining which will recover approximately 50 percent of the coal. If the ground can be allowed to subside, an additional 35 percent of the total amount of coal can be removed by retreat mining. Instead of the butt entries a longwall technique can be used in which the entire side of the panel is mined at once, leaving no pillar. Longwall mining removes 80 to 85 percent of the coal in the mine (TR-049).

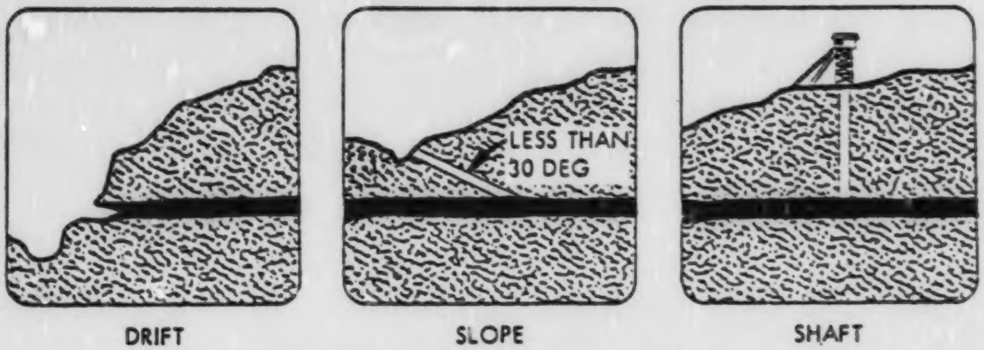

Figure 1. The three types of access used in underground coal mines. (Source: TR-049)

The two types of room and pillar mining (conventional and continuous) are shown in Figure 2. In conventional methods, the coal seam is blasted, loaded by electric loaders on shuttle cars or conveyors, and hauled to the main conveyor or mine rail car. With the electric continuous miner, the coal is scraped from the seam, loaded directly on a conveyor or shuttle car, and transported to the main conveyor or mine rail car. The roof in the room and pillar mine is usually supported by roof bolts but can also be supported by roof trusses (TR-049).

The longwall mining process is shown in Figure 3. The electric longwall miner advances laterally down the panel scraping and shearing the coal from the seam. The coal is automatically loaded in a self-advancing conveyor and transported to the main conveyor or mine rail car. The roof is supported at the mine face by a self-advancing hydraulic system. Behind the supports,

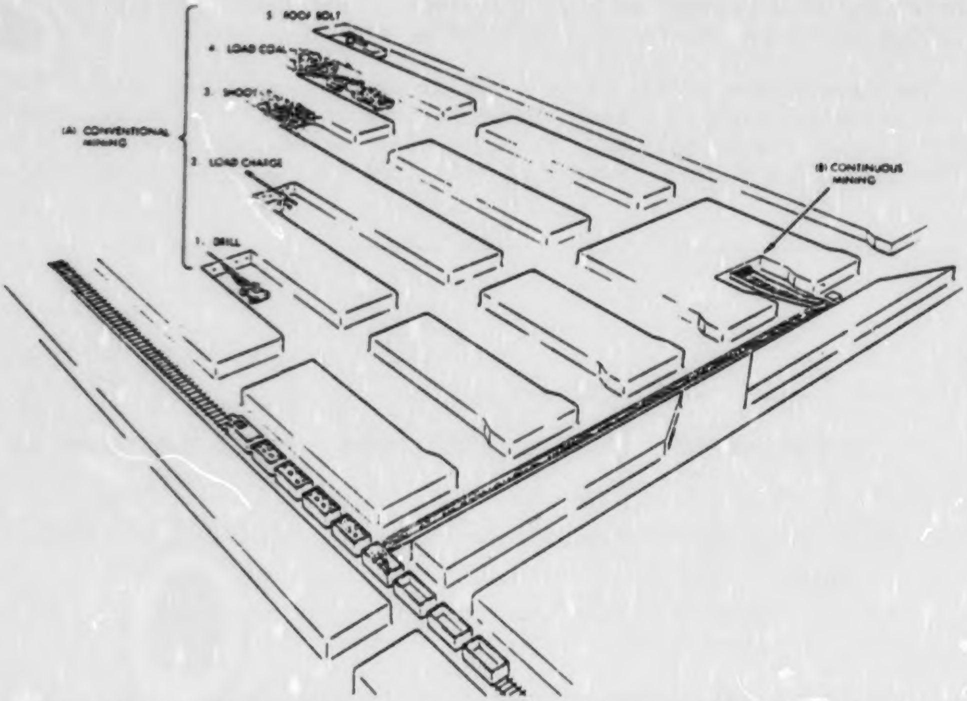
5. ROOF BOLT
4. LOAD COAL
3. SHOOT
(A) CONVENTIONAL MINING
2. LOAD CHARGE
1. DRILL
(B) CONTINUOUS MINING

Figure 2. Illustration of room and pillar mining using conventional blasting and continuous mining techniques. (Source: TR-049)

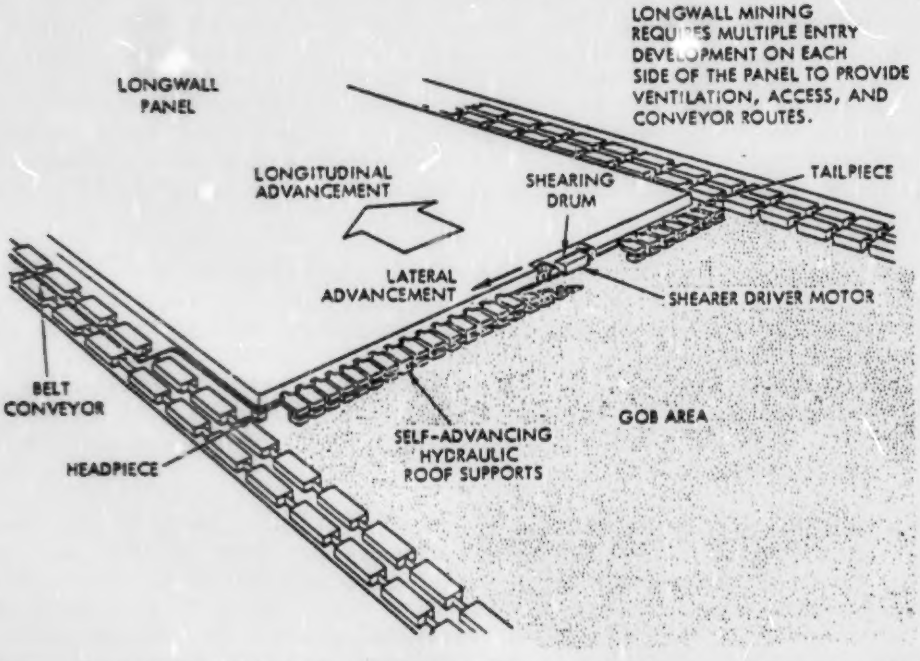
LONGWALL MINING REQUIRES MULTIPLE ENTRY DEVELOPMENT ON EACH SIDE OF THE PANEL TO PROVIDE VENTILATION, ACCESS, AND CONVEYOR ROUTES.
LONGWALL PANEL
LONGITUDINAL ADVANCEMENT
SHEARING DRUM
TAILPIECE
LATERAL ADVANCEMENT
SHEARER DRIVER MOTOR
BELT CONVEYOR
GOB AREA
SELF-ADVANCING HYDRAULIC ROOF SUPPORTS
HEADPIECE

Figure 3. Illustration of longwall mining technique. (Source: TR-049)

the roof is allowed to collapse. The subsidence is sometimes enhanced by blasting to ensure a more controlled cave-in rate (TR-049).

The advantages and disadvantages of room and pillar and longwall mining are given in TABLE 2.

Surface Mining

In 1972 over 595 million tons (540 million metric tons) of bituminous coal were mined; 49 percent of this tonnage was by surface mining methods (GR-156). Surface mining refers to any method involving the removal of surface material (overburden) to expose an underground resource deposit. Strip and auger mining are the surface techniques applicable to coal extraction. In strip mining the overburden is removed in narrow bands, one cut at a time. The two strip mining methods for coal are area and contour. Strip mining has a recovery rate of 80 to 90 percent with coal losses mainly due to spillage and transit methods (ST-166). Strip mining is the most efficient technique from a resource recovery aspect since this type of mining does not require that a certain fraction of the coal be left behind as do underground methods.

Area strip mining is employed on gently rolling to relatively flat terrain and is commonly found in the Midwest and West (GR-156). Topsoil and overburden are first removed and placed in separate storage areas. After the exposed coal seam is mined, overburden and topsoil are replaced and reclamation activities begin. In an established area strip mine, both mining and reclamation activities occur on a simultaneous basis, as shown in Figure 4. The steps involved in an area strip mine are shown in Figure 5.

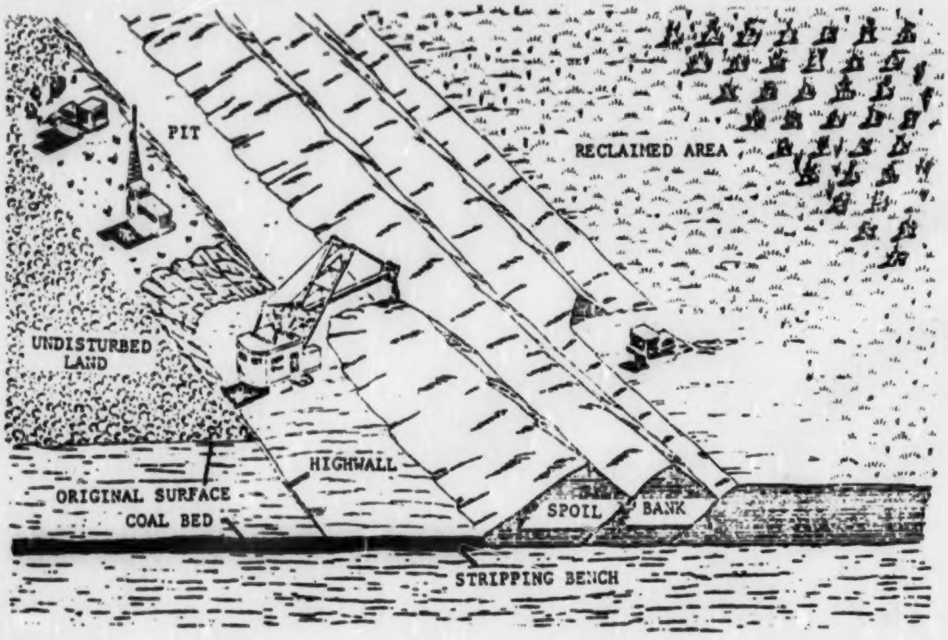

Figure 4. Area strip mining with concurrent reclamation. (Source: GR-156)

TABLE 2. COMPARISON OF CONVENTIONAL, CONTINUOUS, AND LONGWALL MINING (SOURCE: TR-049)

	Longwall	Continuous Room and Pillar	Conventional Room and Pillar
Advantages	. Increases production . Eliminates some permanent room support cost . Cuts cost of ventilation, storage, and rock dusting by 45%. . Provides better ventilation, roof support. . Requires less supervision. . Safer-superior method where roof conditions are poor.	. Involves fewer work cycles, less equipment, and normally produces more per man than conventional mining. . Permits more concentrated mining with fewer supervisory and ventilation problems.	. Effective in coalbeds with high hardness ratings, large partings* and varying dimensions. . Produces less fine coal. . Efficient where roof and floor planes undulate.
Disadvantages	. Requires large, level, straight blocks of coal free from obstructions with seam height minimum of 39". . Requires high capital investment for equipment. . Involves costly equipment moves (30-150 man-shifts to move 300 tons of equipment).	. Not effective where hardness ratings are high, partings are large*, floor and ceiling planes undulate, and roof conditions are poor. . Not effective where seam heights vary greatly. . Cannot be used where coal size is critical. . Provides inefficient face haulage.	. Requires numerous work cycles. . Involves larger crew and more equipment with attendant supervisory and maintenance problems. . Produces less per man. . Provides inefficient face haulage. . Not efficient where roof conditions are poor.

*Partings are impure bands in coalbeds.

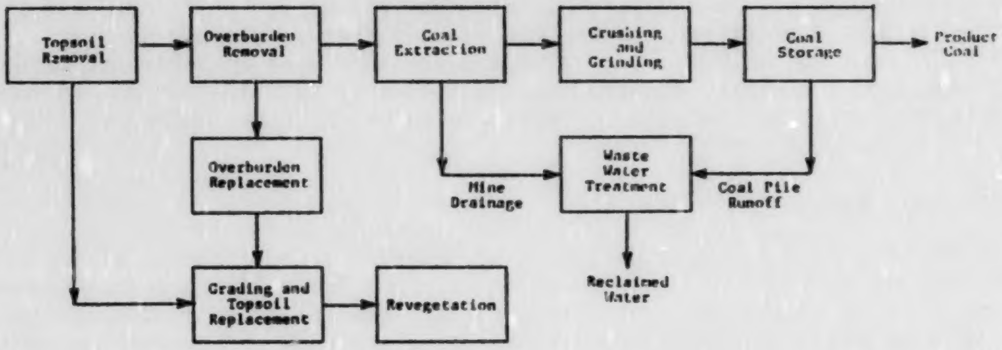
Topsoil Removal
Overburden Removal
Coal Extraction
Crushing and Grinding
Coal Storage
Product Coal
Overburden Replacement
Mine Drainage
Waste Water Treatment
Coal Pile Runoff
Reclaimed Water
Grading and Topsoil Replacement
Revegetation

Figure 5. Steps involved in area strip mining operations. (Source: RA-150)

Contour strip mining is used on terrain ranging from undulating to very steep. Overburden is removed from the coal seam, starting at the outcrop and proceeding along the hillside so that the cut appears as a contour line. Overburden is stacked along the outer edge of the bench that forms. After the uncovered seam is removed, successive cuts are made until the depth of the overburden becomes too great for economical recovery of the coal. Figure 6 illustrates contour mining. Slope reduction, box-cut, head-of-hollow fill, mountain-top removal and block are contour mining methods for mining on steep slopes (GR-156).

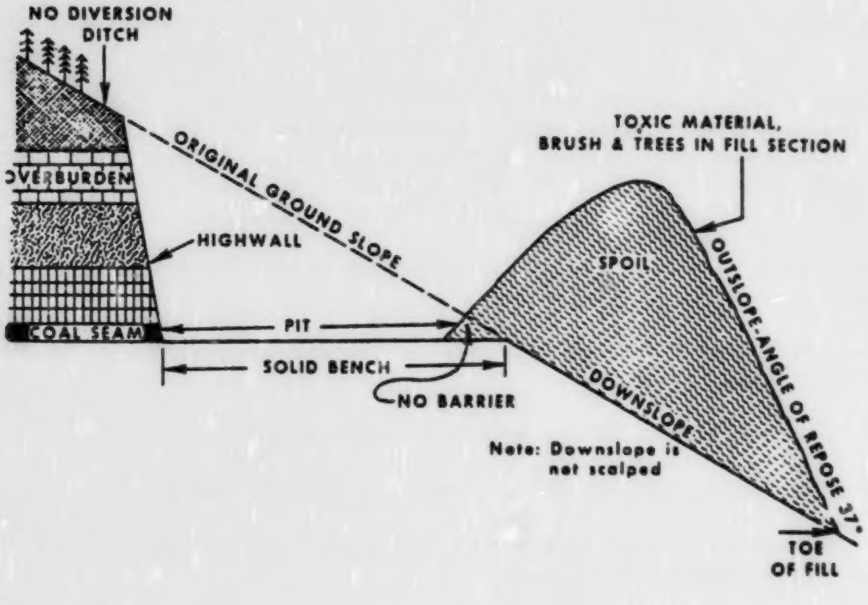
NO DIVERSION DITCH
ORIGINAL GROUND SLOPE
TOXIC MATERIAL, BRUSH & TREES IN FILL SECTION
OVERBURDEN
HIGHWALL
SPOIL
OUTSLOPE-ANGLE OF REPOSE 37°
COAL SEAM
PIT
SOLID BENCH
NO BARRIER
DOWNSLOPE
Note: Downslope is not scalped
TOE OF FILL

Figure 6. Conventional contour mining. (Source: GR-156).

Auger mining is usually associated with contour strip mining. When the side walls of a contour mine become too steep for strip mining, augers are used to recover additional coal. Augering produces coal by boring horizontally into the coal seam, and the coal is recovered in chips similar to wood chips from a drill bit (GR-156). Large augers may drill in excess of 200 feet into a coal seam (EN-096).

Underground Coal Gasification

Underground coal gasification is a concept for converting coal deposits into fuel gas by reaction with oxygen and steam. Present work in this area is in the experimental and developmental stages. Despite decades of research in several countries, no viable process has been produced, and formidable technical problems must be overcome before underground gasification can be commercialized. Both physical and indicated economic successes have been so limited that future large production facilities are unforeseen in the near future. Therefore, underground gasification and its impacts will be only briefly discussed in this report.

The first step in underground coal gasification is the preparation of the coal bed by linking the inlet and outlet boreholes or shafts driven into the coal seam. Linking processes increase the permeability of the coal bed to allow for a smoother, faster gasification process. Some coal seams are naturally quite permeable and do not require this preparation, but the majority require pretreatment. Methods of linking the desired points in the bed include electrolinking, pneumatic linking, and fracturing by hydraulic presure, explosives, or nuclear reaction (GA-104, HU-079, KA-124).

The gasification of the coal seam includes the introduction of the gasifying agents, contact of the agents with the coal, recovery and purification of the combustion products, and control of the process. The gasifying agents are oxygen, steam, and carbon dioxide. These gases, introduced in varying proportions, react with the pretreated coal seam to produce an exit gas containing carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), hydrogen (H_2), water vapor (H_2O), nitrogen (N_2), and various volatile organics from the coal seam (GA-104). The raw gas also contains heavy entrained hydrocarbons and hydrogen sulfide (H_2S) and must be purified.

Experience with coal gasification has revealed the following disadvantages (GA-104, HU-079, KA-124):

(1) The heating value of the gas is low and generally decreases with time.

(2) Gases leak out of the gasification area.

(3) The percentage of coal energy recovered is small.

(4) Ground water can penetrate the gasification zone and extinguish the fire.

(5) The burned-out area can collapse causing surface subsidence problems.

(6) Direction of the flame front is hard to control.

(7) Coal beds often lack uniformity which produces a poor burning front.

Despite these disadvantages, underground coal gasification has the following advantages over conventional mining (GA-104):

(1) Equipment cost is much less.

(2) Underground labor and the inherent hazards are eliminated.

(3) Coal seams which are deep and not minable can be recovered by underground gasification.

Further development of the technology will determine the extent of eventual application of underground coal gasification.

COAL CLEANING

Physical Coal Cleaning

Physical coal cleaning involves crushing, grinding, sizing, solid separation, washing, and flotation in various combinations designed to reduce inorganic matter. These methods are applied at the mine site. Physical coal cleaning is a proven industrial technique used to remove portions of the sulfur and ash contents of coal. Although the sulfur present in coal exists in both inorganic and organic forms, physical cleaning is only effective in removing inorganic sulfur. In addition to reducing the coal sulfur content, physical cleaning results in an increase in the per pound heat content of the coal due to the partial removal of ash.

The physical cleaning of coal in this study is based on dense media washing. Run-of-mine coal is crushed to a top size of three inches and sent to a dense media washing unit. In this unit the coal is separated into two layers by washing with a liquid of 1.6 specific gravity. The heaviest fraction, which contains the ash and refuse material, is removed from the bottom of the unit. The so-called "float material" is removed and crushed to a top size of 3/8 inch. Screening of this material yields two fractions. The smaller fraction is sent to a dense media cyclone where it is treated with a liquid of 1.35 specific gravity. The float coal of density less than 1.35 from the dense media cyclones is washed, wet ground to 30 mesh x 0 and centrifugally dried. The 30 mesh x 0 fraction from the "float material" screening is sent to a froth floatation unit where the fines are frothed (after treating with alcohols, pine oil or kerosene to render the coal particles nonwettable and to facilitate agglomeration), skimmed, thickened and vacuum-filtered. The two 30 mesh x 0 streams are combined to yield the physically-cleaned coal product (RA-150, ZI-014).

Refuse from the process is collected and stored until time of disposal. The liquid effluent streams, containing large quantities of suspended solids, are sent to holding ponds where the solids settle and the clear supernatant liquid is returned to the process. Figure 7 is a block diagram of the physical coal-cleaning process.

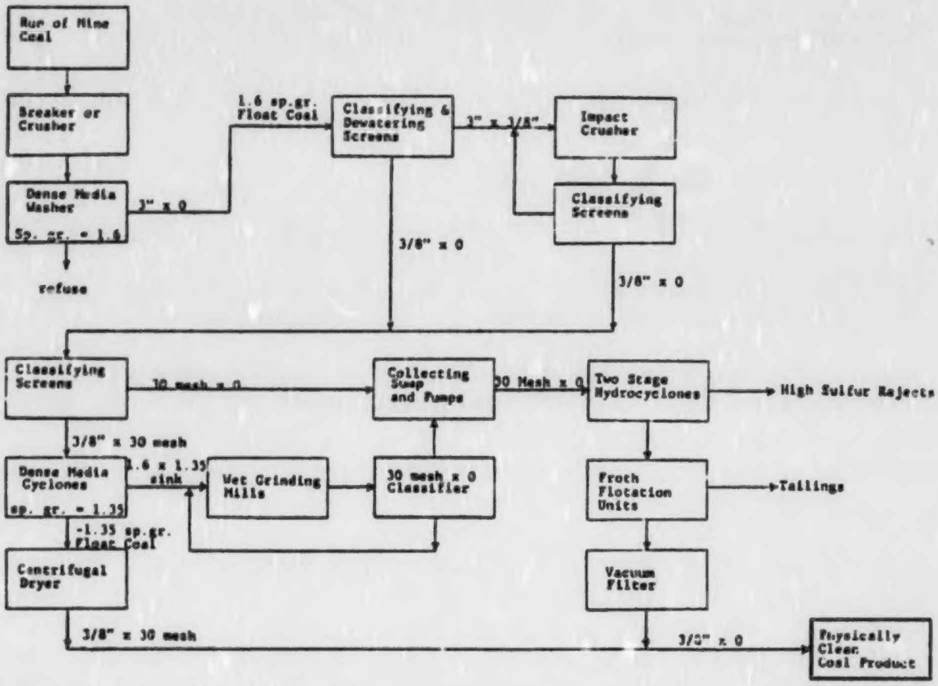
Run of Mine Coal
Breaker or Crusher
Dense Media Washer
Sp. gr. = 1.6
refuse
3" x 0
1.6 sp.gr. Float Coal
Classifying & Dewatering Screens
3" x 3/8"
Impact Crusher
Classifying Screens
3/8" x 0
3/8" x 0
Classifying Screens
30 mesh x 0
Collecting Sump and Pumps
30 Mesh x 0
Two Stage Hydrocyclones
High Sulfur Rejects
3/8" x 30 mesh
Dense Media Cyclones
sp. gr. = 1.35
1.6 x 1.35 sink
Wet Grinding Mills
30 mesh x 0 Classifier
Froth Flotation Units
Tailings
-1.35 sp.gr. Float Coal
Centrifugal Dryer
Vacuum Filter
3/8" x 30 mesh
3/8" x 0
Physically Clean Coal Product

Figure 7. Physical coal-cleaning plant processing diagram. (Source: RA-150)

Current physical coal-cleaning processes remove about 50 percent of the pyritic sulfur and lose some 10 percent of the coal (KA-124).

Chemical Coal-Cleaning

Chemical coal-cleaning or desulfurization involves treating coal with a reagent capable of converting the sulfur to a soluble or volatile form. A wide variety of possible leaching solutions such as nitric acid (HNO_3), hydrofluoric acid (HFl), chlorine (Cl), molten caustic, aqueous caustic, ammonia (NH_3), steam, and organic solvents have been tested (BA-234). Although several of these methods have been reported to be successful, chemical coal-cleaning is not currently employed commercialy. Several experimental studies are in progress however. Two important processes being developed are the Meyers and Battelle processes. Descriptions of the two processes follow.

Meyers Coal Desulfurization Process

The Meyers process uses an aqueous solution of ferric sulfate [$Fe_2(SO_4)_3$] at about 100°C to remove pyritic sulfur (S) from coal. Ferrous sulfate ($FeSO_4$), excess sulfate as sulfuric acid (H_2SO_4), and elemental sulfur (S) are formed during the reaction. The elemental sulfur is removed by dissolution in a warm naphtha bath. The coal slurry from the sulfur extraction vessel goes to a washer, filter, and dryer where the coal is separated from the aqueous solution which retains the sulfate. Ferric sulfate is regenerated from ferrous sulfate by reaction with air or oxygen. The excess ferric and ferrous sulfate are removed from the system. Figure 8 diagrams the Meyers process. The overall leaching reaction, regeneration reaction, and net overall reaction are shown in equations 1 through 3 respectively:

$$\mathrm{Fe\ S_2 + 4.6\ Fe_2(SO_4)_3 + 4.8\ H_2O \rightarrow 10.2\ FeSO_4 + 4.8\ H_2SO_4 + 0.8\ S} \tag{1}$$

$$\mathrm{9.6\ FeSO_4 + 4.9\ H_2SO_4 + 2.4\ O_2 \rightarrow 4.8\ Fe_2(SO_4)_3 + 4.8\ H_2O} \tag{2}$$

$$\mathrm{FeS_2 + 2.4\ O_2 \rightarrow 0.2\ Fe_2(SO_4)_3 + 0.6\ FeSO_4 + 0.8\ S} \tag{3}$$

This process removes 90 to 95 percent of the pyritic sulfur with a loss of less than 5 percent of the coal; the heat content of the product coal is also increased because there is less ash. Only organic sulfur is left in the coal (CA-190, KA-124).

Battelle Hydrothermal Process

In this process, hydrothermal technology is applied to extract sulfur from coal using an aqueous caustic solution as the leachant. The process involves heating a water slurry of coal and sodium hydroxide to convert both pyritic and organic sulfur and part of the ash to soluble species. The five stages of the process are (1) coal preparation, (2) hydrothermal treatment, (3) fuel separation, (4) fuel drying, and (5) leachant regeneration. Figure 9 outlines the process. Temperatures on the order of 430 to 650° F and pressures of 350 to 2,500 pounds per square inch (psi) are used (WO-055).

In the sulfur removal autoclave, almost all the pyritic sulfur and up to 70 percent of the organic sulfur are dissolved, primarily as sodium sulfide. Part of the ash and about 5 percent of the coal also dissolve. The final product is a dry, granular solid (HA-319, WO-055).

Regeneration of the spent leachant begins by sparging the solution with carbon dioxide to convert the sodium sulfide to hydrogen sulfide and sodium carbonate. The released hydrogen sulfide can be converted to elemental sulfur for recovery. Next, the sodium carbonate reacts with lime to form a sodium hydroxide solution and a precipitate of calcium carbonate. This solution can then be filtered, concentrated and recycled. The lime can be recovered by calcining the limestone.

The Battelle process has been tested in a small, continuous operation plant processing 500 pounds of coal per day. The next step will be the testing of a 50 ton-per-day pilot plant.

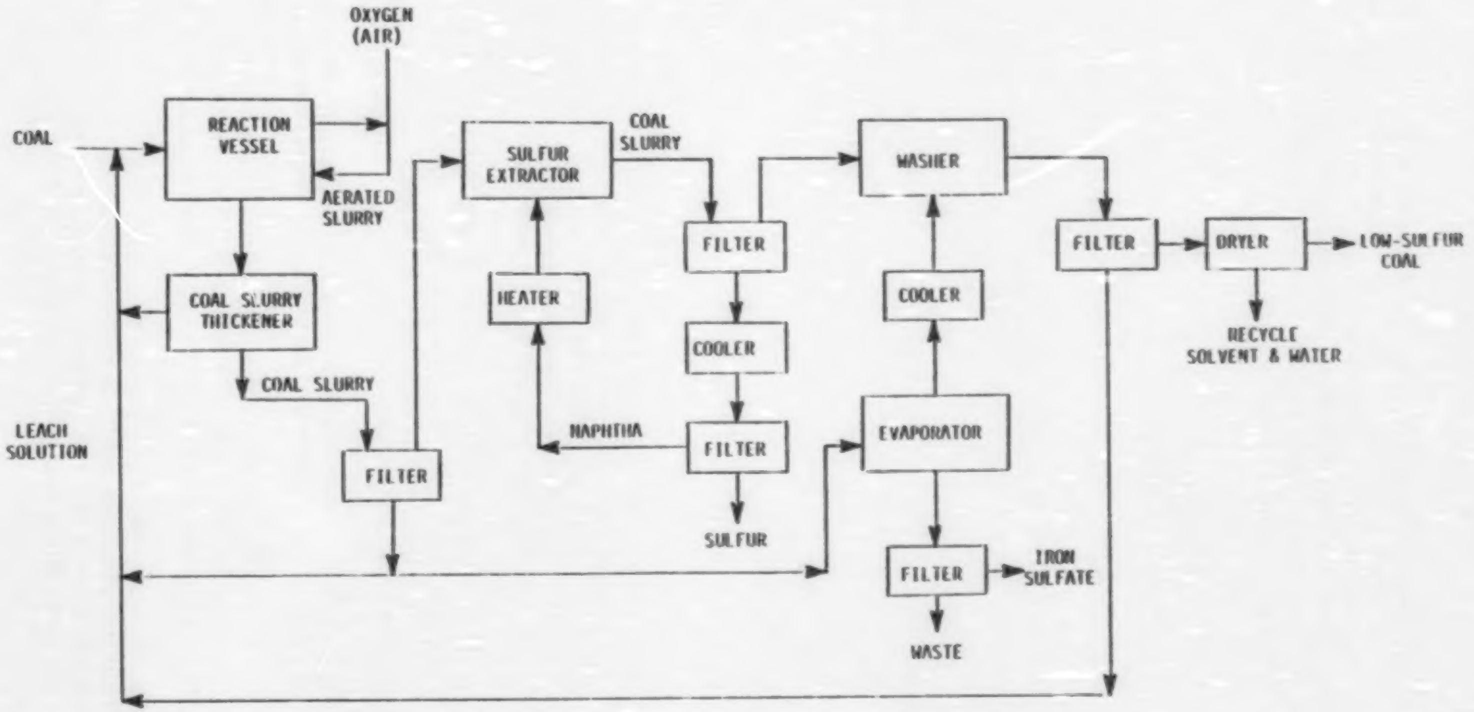
OXYGEN (AIR)
COAL
REACTION VESSEL
AERATED SLURRY
SULFUR EXTRACTOR
COAL SLURRY
WASHER
FILTER
DRYER
LOW-SULFUR COAL
COAL SLURRY THICKENER
HEATER
FILTER
COOLER
RECYCLE SOLVENT & WATER
COOLER
COAL SLURRY
LEACH SOLUTION
NAPHTHA
FILTER
EVAPORATOR
FILTER
SULFUR
FILTER
IRON SULFATE
WASTE

Figure 8. Flow sheet for Meyers process.

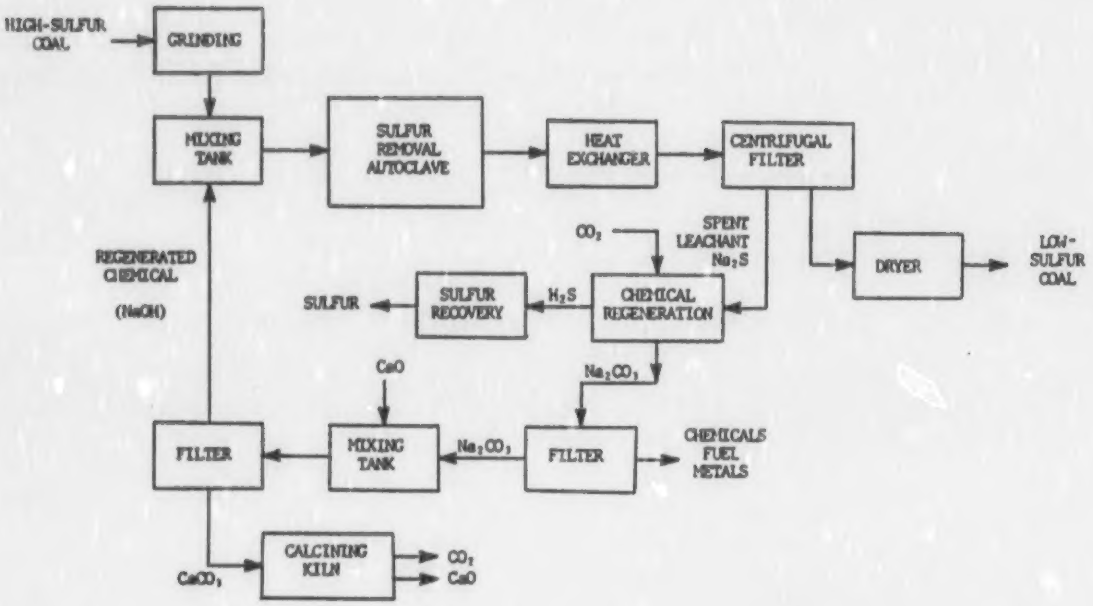
HIGH-SULFUR COAL
GRINDING
MIXING TANK
SULFUR REMOVAL AUTOCLAVE
HEAT EXCHANGER
CENTRIFUGAL FILTER
CO_2
SPENT LEACHANT Na_2S
DRYER
LOW-SULFUR COAL
REGENERATED CHEMICAL
(NaOH)
SULFUR
SULFUR RECOVERY
H_2S
CHEMICAL REGENERATION
Na_2CO_3
CaO
FILTER
MIXING TANK
Na_2CO_3
FILTER
CHEMICALS FUEL METALS
$CaCO_3$
CALCINING KILN
CO_2
CaO

Figure 9. Schematic of hydrothermal coal process showing reactions and product stream.

COAL SLURRY PIPELINE

Coal slurry pipeline technology has proven to be a commercially successful alternative for coal transport. Constructed by Consolidated Coal Co., the first multi-station coal slurry pipeline began operation in Ohio in 1957 and ran for six years. It achieved an availability factor of better than 98%. In August 1970 the Black Mesa pipeline began transporting coal 273 miles from a mine in northeastern Arizona to the Mohave Power Plant in Southern Nevada. The availability factor of this four-station line was greater than 99% in 1972 and in 1973 (MO-113).

The success of the Black Mesa pipeline has led to the planning and construction of new coal slurry pieplines for the development of new energy reserves. Planned and constructed coal slurry pipelines are summarized in TABLE 3. The impending expansion of the coal slurry piepline system requires discussion in this report.

TABLE 3. SUMMARY OF COMMERCIAL COAL SLURRY PIPELINES
(SOURCE: EN-140, EN-202, WA-139)

Status	System or location	Length (miles)	Diameter (inches)	Annual thruput (millions tons/year)	Initial operation
Constructed	Consolidated Coal Co.	108	10	1.3	1957
	Black Mesa	273	18	4.8	1970
Planned	Nevada Power Co. (Utah to Nev.)	180	24	10	Planned
	Salt River (N. Mex. to Ariz.)	180	16	4	Planned
	Houston Power & Light Co. (Colo. to Tex.)	1100	18	7	Planned
	Energy Transportation Systems, Inc. (Wyo. to Ark.)	1030	38	25	Planned
	Canada	500	24	12	Planned
	Gulf Interstate - Northwest Pipeline (Wyo. to Wash.)	800	30	16	Planned

The hydraulic transport of solids is a well-developed technology (AD-021, AU-006, BA-233, DU-061, GO-055, PI-044, SK-024, ST-188). Materials transported by slurry pipelines include coal, limestone, magnetite, gilsonite, copper concentrate, phosphate, and tailing. Flow regimes have been identified and classified; their characteristics are well understood and can be predicted by laboratory tests and mathematical models.

Figure 10 is a schematic of a coal slurry pipeline showing the relationship of the pipeline to the coal source and to the coal user. At the coal slurry preparation plant, the coal is broken, washed, ground to a maximum size of 14 mesh, and slurried. The sizing of the coal is accomplished by dry crushing and by wet grinding and rod mill pulverization (LO-084, MO-103, MO-126). In the rod mills, water is introduced to the pulverized coal to form the slurry. The concentration of coal, by weight, is in the range of 45-55% (WA-043, WA-140). The weight percent solids of the Black Mesa pipeline is actually held at 46.5 ± 0.1% (KA-124). The slurry is pumped into mechanically-agitated storage tanks where an average concentration of solids is maintained. Then the slurry is fed into the pipeline from the storage tanks by a centrifugal charge pump, followed by a high pressure positive displacement pump. The Black Mesa pipeline has a 1000-foot loop circling the preparation plant where the behavior of the slurry is monitored before leaving the plant

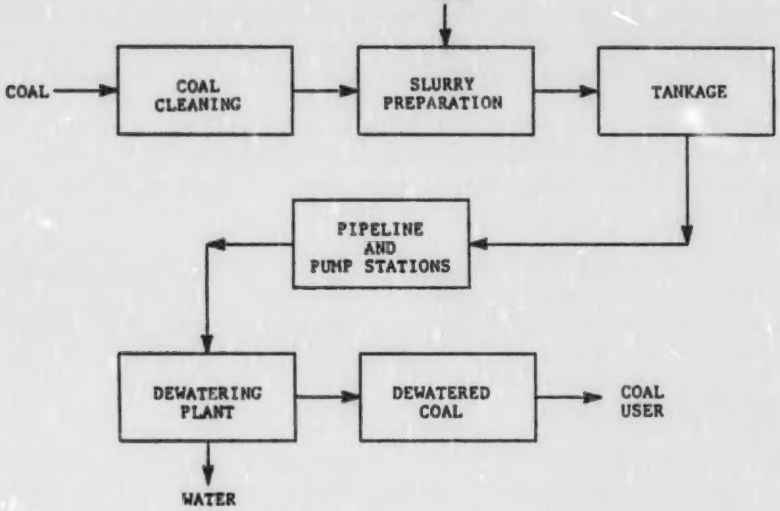

Figure 10. Schematic of coal slurry pipeline.

boundaries. An average flow velocity of 5.0 ft/sec is maintained throughout the pipeline by pumps that are spaced along the line (WA-125, WA-126). Pump stations are spaced at 60-100 mile intervals (AU-019, CO-197, HU-088, WA-153). The pipeline terminates at a power plant where the slurry is discharged to holding tanks. This is followed by dewatering through centrifuges and further size reduction by conventional ball mills. The pulverized coal is then injected into the boilers. Coal slurry pipelines can, of course, be used to deliver coal to other users such as gasification plants. Most of the new gasification processes require a fine feed, but the Lurgi process cannot use coal that has been ground as fine as is necessary for pipeline transport.

COAL GASIFICATION

Coal gasification is a technique by which solid coal is converted to a gaseous product by reaction with air, oxygen, steam, carbon monoxide, hydrogen, or mixtures of these gases. The two categories of gasification processes, classified according to the heating values of the synthesis gases, are (1) high-Btu gasification and (2) low-and-intermediate-Btu gasification. High-Btu gas has a heating value of about 950 to 1000 Btu/scf (standard cubic foot) while low-Btu gas has a value of about 135 to 200 Btu/scf. High-Btu gasification is aimed toward developemnt of a substitute for natural gas which can be economically piped over long distances. Low-Btu gas is less expensive and will be used for producing a clean fuel for utility plants or industrial sites.

Several factors are important in determining the heating value of the synthesis gas. One such factor is whether air or oxygen is used as the oxidizing agent in the gasification step. Pure oxygen is used to produce high-Btu gas and air is used to produce low-Btu gas. Another factor is the presence or absence of upgrading facilities. Upgrading the synthesis gas by shift conversion and methanation produces a high-Btu gas. The methanation step developed in one gasification project presumably could be used with other gasification processes. Therefore some gasification processes could be placed in either category depending upon the process details.

Gasification processes may also be classified according to gasifier characteristics such as dry-ash moving bed, slagging moving bed, dry-ash fluid bed, ash agglomerating fluid bed, entrainment, slagging entrainment, and molten bath.

In the following two sections, high-and-low-Btu gasification and the processes normally associated with each are described briefly. No attempt is made to provide complete, detailed descriptions of the processes since these are available in the literature.

High-Btu Coal Gasification

The objective of all high-Btu coal gasification processes is the conversion of coal to essentially pure methane or substitute natural gas (SNG). The heating value of this pipeline-quality gas is about 1,000 Btu/scf.

All SNG-from-coal processes utilize some kind of a gasifier to produce a synthesis gas which contains CH_4, CO, H_2O, H_2, and CO_2. After leaving the gasifier, the synthesis gas goes through several processing steps to upgrade it to pipeline quality gas. Figure 11 is a general schematic of the gasification process. Technology common to all the processes are solids separation and cooling, shift reaction, acid gas removal, sulfur recovery, catalytic methanation, and drying. While the specific means of accomplishing the gas processing steps may vary from process to process, the basic principles of

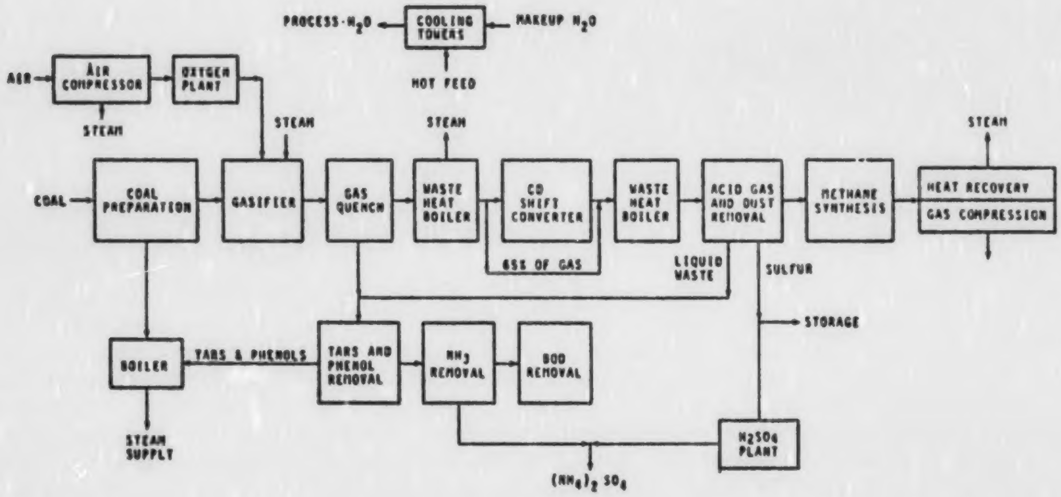
PROCESS H_2O
COOLING TOWERS
MAKEUP H_2O
HOT FEED
AIR
AIR COMPRESSOR
STEAM
OXYGEN PLANT
STEAM
STEAM
STEAM
COAL
COAL PREPARATION
GASIFIER
GAS QUENCH
WASTE HEAT BOILER
CO SHIFT CONVERTER
WASTE HEAT BOILER
ACID GAS AND DUST REMOVAL
METHANE SYNTHESIS
HEAT RECOVERY
GAS COMPRESSION
65% OF GAS
LIQUID WASTE
SULFUR
STORAGE
BOILER
TARS & PHENOLS
TARS AND PHENOL REMOVAL
NH_3 REMOVAL
BOD REMOVAL
STEAM SUPPLY
H_2SO_4 PLANT
$(NH_4)_2SO_4$

Figure 11. Simplified process flow diagram of typical high-Btu coal gasification complex.

each step are common to all processes. The major distinguishing feature of the various high-Btu gasification processes is the design of the gasifier.

The catalytic shift and methanation reaction steps are the only SNG-from-coal process operations which have not yet been demonstrated on a commercial scale. Lurgi reactor technology has been proven in several foreign installations. Current research and development activities in this country are concerned mainly with the development of competitive gasification reactor designs.

The following paragraphs briefly describe current high-Btu coal gasification processes. The Lurgi gasifier is the only process ready for commercial application. The ad hoc panel on "Evaluation of Coal Gasification Technology" of the National Academy of Engineering has judged the HYGAS steam-oxygen, Synthane, BI-GAS, and CO_2 Acceptor processes as the most advanced of the other processes and should be rapidly developed to the demonstration plant stage so that a decision can be made as to their commercial applicability. The panel also judged the U.S. Bureau of Mines Hydrane Process to be promising (NA-115). Of course, this does not mean that the other processes, which are generally more proprietary, cannot become commercial realities. Available information on specific development plans for each of the emerging gasification technologies is summarized in TABLE 4. The advantages, disadvantages, or economic aspects of the processes are not evaluated in this report.

The major distinguishing feature of the various gasification processes lies in the gasifier section. In this section raw coal reacts to produce a synthesis gas which can be upgraded to pipeline quality gas. The differences among the processes are found in the operating temperatures, pressures, mechanical characteristics of the gasifier and the means of supplying heat for the gasification reactions. These reactions for high-Btu gasification are shown in equations 4 through 7:

$$\text{Coal} \rightarrow CH_4 + \text{Char} + \text{Heat} \tag{4}$$

$$C + 2H_2 \rightarrow CH_4 + \text{Heat} \tag{5}$$

$$C + H_2O + \text{Heat} \rightarrow CO + H_2 \tag{6}$$

$$2C + O_2 \rightarrow 2CO + \text{Heat} \tag{7}$$

Lurgi Process

The Lurgi gasifier is a moving bed, steam-oxygen gasifier. Noncaking or slightly caking coal is crushed, fed through a lock hopper, and distributed in the gasifier via a revolving grate. Steam and oxygen injected at the bottom of the gasifier are distributed through a second revolving grate which also provides bed support and regulates the ash removal rate. Ash is removed from the gasifier via a lock hopper and water quenched. Figure 12 shows the Lurgi gasifier.

The steam and oxygen react with char to produce heat and synthesis gas. This gas rises while the coal bed moves downward. As the coal enters the top of the gasifier, the coal devolatilizes and forms more methane. The process creates three zones in the gasifier: (1) the coal preheat zone, (2) the reaction zone,

TABLE 4. HIGH-BTU COAL GASIFICATION TECHNOLOGY

Process Name and Developer	Development Status	Development Plans
Lurgi Lurgi Mineralotechnik G.m.b.H.	Several commercial-scale plants, approximately 250-MM scfd capacity, are under construction	Demonstration of technology on commercial scale
HYGAS Institute of Gas Technology	75 tons per day (tpd) pilot plant is operational	Preliminary design of 80-MM scfd demonstration plant completed
BI-GAS Bituminous Coal Research, Inc.	Methanation reactor tests being performed	Operation of 120 tpd pilot plant
Synthane U.S. Bureau of Mines	75 tpd pilot plant operational	Demonstration size plant
CO_2 Acceptor Consolidation Coal Co.	40 tpd plant operational	Demonstration size plant
Hydrane U.S. Bureau of Mines	12 lb/hr process development unit operational	Scale up to 10-30 tpd pilot plant
ATGAS Applied Technology Corp.	Batch testing on bench scale	
Molten Salt M. W. Kellogg Co.	Tested in 5-in diameter reactor	Testing in 30-in diameter reactor
COGAS Cogas Development Co.		Pilot plant to be used in conjunction with COED process
Union Carbide Process Union Carbide-Battelle-Chemico	Components of process tested during 1960's	Operation of 25 tpd pilot plant
Solution Gasification Stone and Webster/ General Atomic	Tested on bench scale	Demonstration plant using nuclear reactors to provide heat for hydrogen generation
GRD Process Garrett Research and Development	Tested in 50 lb/hr unit	Seeking support for 250 tpd pilot plant
EXXON Process EXXON Corp.	Tested in 1/2 tpd unit	Construction of demonstration plant deferred

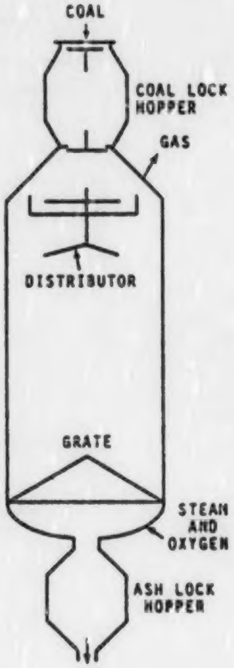

Figure 12. Lurgi gasifier.

and (3) the ash zone. The temperature at the bottom of the gasifier is about 1800°F, while the temperature at the top of the gasifier is about 1100°F. The Lurgi gasifier operates at a pressure of 300-500 psi (FE-068). About 86% of the coal is gasified and the remaining 14%, mostly carbon, is burned in the combustion zone to provide the overall heat for the gasification and devolatilization reaction (MO-150).

HYGAS Process

The HYGAS Process gasifies coal by direct hydrogenation at high pressures. The Institute of Gas Technology (IGT) has developed three methods for generating the hydrogen to be used in the gasifier. These three processes are the electrothermal, steam-iron, and steam-oxygen processes. The National Academy of Engineers has judged the steam-oxygen process to have the greatest potential for success (NA-115), and IGT has chosen this to be the first method integrated with the HYGAS unit (LE-133). Figure 13 illustrates the HYGAS process and associated steam-oxygen process.

The HYGAS gasifier section consists of (1) coal pretreatment, (2) slurry preparation, (3) a fluidized-bed, two-stage gasifier, and (4) hydrogen production.

Crushed coal is fed to the pretreater where the caking tendencies of the coal are destroyed by a hot air stream. The treated coal mixes with a light oil formed in the gasifier and is injected into the top of the gasifier

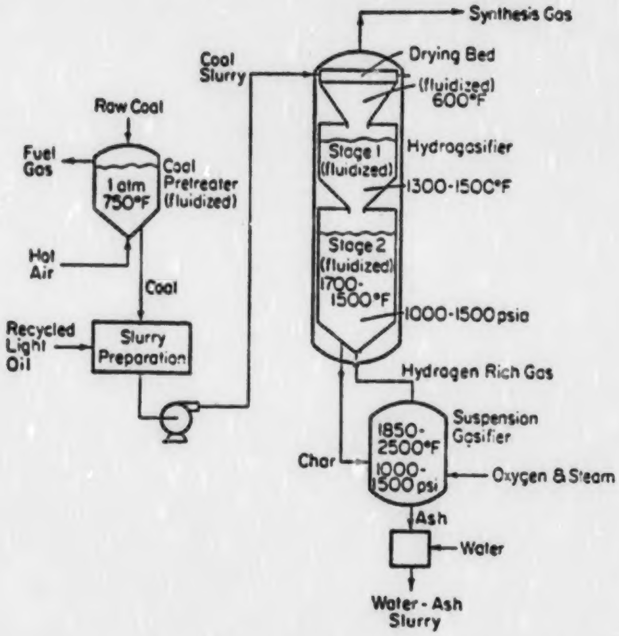
Synthesis Gas
Coal Slurry
Drying Bed
(fluidized) 600°F
Raw Coal
Fuel Gas
1 atm 750°F
Coal Pretreater (fluidized)
Stage 1 (fluidized)
Hydrogasifier
1300-1500°F
Hot Air
Coal
Stage 2 (fluidized) 1700-1500°F
1000-1500 psia
Recycled Light Oil
Slurry Preparation
Hydrogen Rich Gas
1850-2500°F
Suspension Gasifier
Char
1000-1500 psi
Oxygen & Steam
Ash
Water
Water - Ash Slurry

Figure 13. HYGAS coal gasification process. (Source: KA-124)

in a slurry form. At the top of the gasifier the light oil evaporates and the dried coal falls into the upper part of the gasifier. The coal reacts with rising hot synthesis gas at a temperature of 1300-1500°F.

The hydrogen-rich gas and steam injected into the bottom of the gasifier react with the char formed in the upper stages of the gasifier to form methane concurrently with the formation of CO and H_2 from the steam-carbon reaction. The lower portion of the gasifier operates at 1700-1800°F. The gasifier pressure is 1000-1500 psi. Figure 14 gives a more detailed diagram of the gasification section.

Unreacted char from the bottom of the gasifier is sent to a hydrogen-rich gas generator where it reacts with steam to yield H_2 and CO. In the steam-oxygen process, heat for the reaction of steam with char to form H_2 and CO is supplied by combustion of a portion of the char with oxygen in a fluid bed (BO-117, LE-133, SC-249).

A 75 ton/day pilot plant was finished in 1971, which included an electrothermal gasifier (FE-068). A 2 ton/day fluidized bed reactor utilizing steam and oxygen to produce a hydrogen-rich gas has also been constructed. The design and evaluation of a HYGAS demonstration plant using steam-oxygen gasification for hydrogen generation is in progress, and it is possible that a commercial plant could be ready for operation before the end of 1980 (LE-133, SC-249).

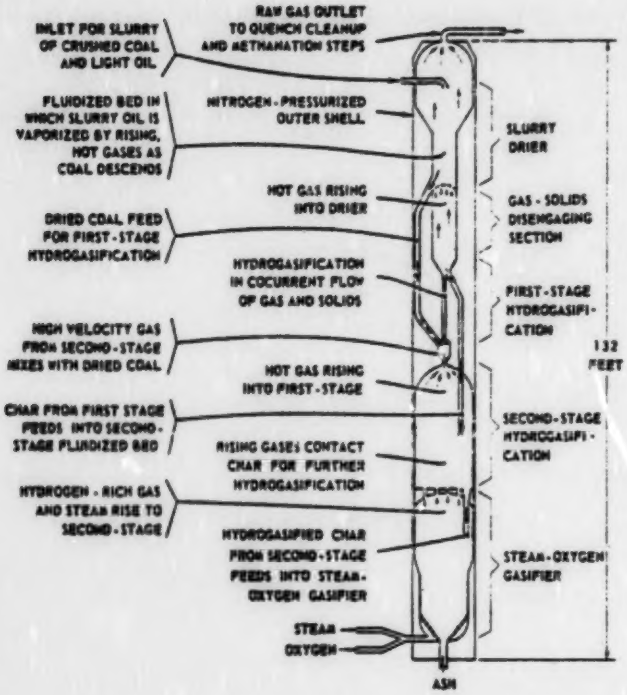
INLET FOR SLURRY OF CRUSHED COAL AND LIGHT OIL
RAW GAS OUTLET TO QUENCH CLEANUP AND METHANATION STEPS
FLUIDIZED BED IN WHICH SLURRY OIL IS VAPORIZED BY RISING, HOT GASES AS COAL DESCENDS
NITROGEN-PRESSURIZED OUTER SHELL
SLURRY DRIER
HOT GAS RISING INTO DRIER
GAS-SOLIDS DISENGAGING SECTION
DRIED COAL FEED FOR FIRST-STAGE HYDROGASIFICATION
HYDROGASIFICATION IN COCURRENT FLOW OF GAS AND SOLIDS
FIRST-STAGE HYDROGASIFICATION
132 FEET
HIGH VELOCITY GAS FROM SECOND-STAGE MIXES WITH DRIED COAL
HOT GAS RISING INTO FIRST-STAGE
CHAR FROM FIRST STAGE FEEDS INTO SECOND-STAGE FLUIDIZED BED
SECOND-STAGE HYDROGASIFICATION
RISING GASES CONTACT CHAR FOR FURTHER HYDROGASIFICATION
HYDROGEN-RICH GAS AND STEAM RISE TO SECOND-STAGE
HYDROGASIFIED CHAR FROM SECOND-STAGE FEEDS INTO STEAM-OXYGEN GASIFIER
STEAM-OXYGEN GASIFIER
STEAM
OXYGEN
ASH

Figure 14. IGT pilot plant hydrogasification reactor section.
(Source: LE-133)

Synthane Process

The Synthane Process, developed by the U. S. Bureau of Mines, converts bituminous coal, sub-bituminous coal, and lignite into SNG. The process uses a two-stage, fluidized-bed gasifier with a free-falling pretreatment stage. Pretreatment of caking coals and gasification occur in one reactor.

Crushed coal, fed into the top of the gasifier, reacts with steam and oxygen in a free-falling manner that destroys the caking properties of the coal in addition to partially devolatilizing the coal. After pretreatment the coal enters the hydrogasification stage of the gasifier and then the gasification section. Both of these stages operate as a fluidized bed. At the bottom of the gasifier, steam and oxygen are injected and char and ash are removed. The steam, oxygen, and char react to produce a synthesis gas. The gasification stage operates 1750-1850°F and the hydrogasification stage operates at 1100-1450°F. The entire gasifier is under 600-1000 psi pressure (US-109, FO-059). Figure 15 is a schematic of the Synthane Process.

The Synthane Process development started in 1961 in a study of pretreating caking coals in a fluid bed. Work was also done to develop a suitable methanation reactor. Two systems were studied: (1) a hot gas recycling process and (2) a tube wall reactor process. Forney and McGee (FO-050) have discussed research results and prototype plant design. Construction of a 72 ton/day pilot plant was completed in the fall of 1974. A previous study for the EPA has evaluated pollution control for the process (KA-142).

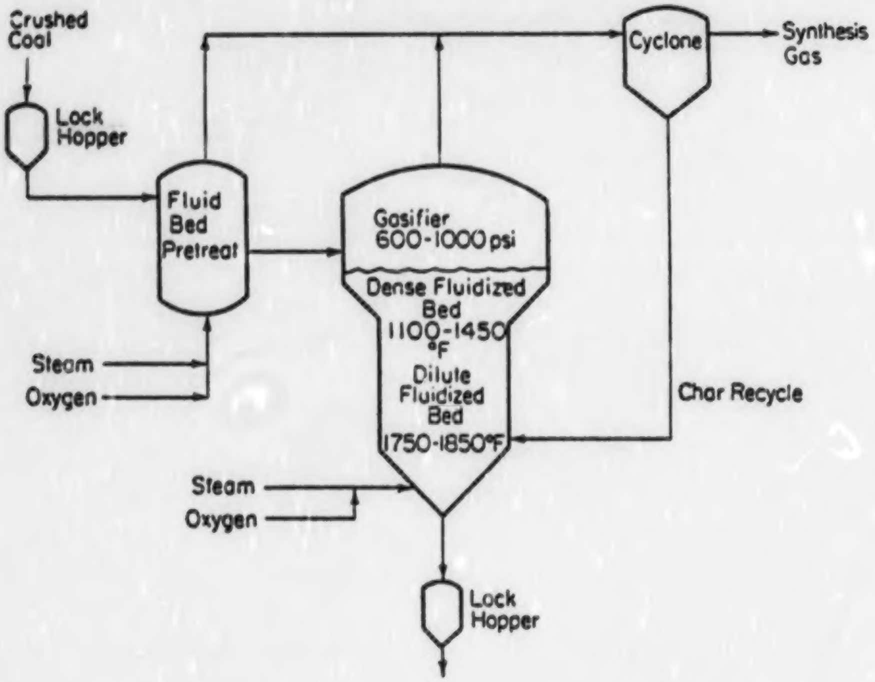
Crushed Coal
Lock Hopper
Fluid Bed Pretreat
Steam
Oxygen
Gasifier 600-1000 psi
Dense Fluidized Bed 1100-1450 °F
Dilute Fluidized Bed 1750-1850°F
Steam
Oxygen
Lock Hopper
Cyclone
Synthesis Gas
Char Recycle

Figure 15. Synthane coal gasification process.
(Source KA-124)

BI-GAS Process

The BI-GAS Process uses a two-stage, high-pressure oxygen-blown gasifier with an entrained bed. Pulverized coal and steam are fed into the first stage of the entrained flow gasifier. Upon contact with the hot synthesis gas rising from Stage 2, the coal rapidly undergoes devolatilization to produce methane and an active carbon char, which reacts with steam to yield more synthesis gas. The char and gas are swept out of the top of the gasifier to the char separation cyclone where the char is removed and returned, along with steam and oxygen, to the second stage of the gasifier. In this lower stage of the gasifier, the carbon char is gasified to produce a hot synthesis gas which rises to the first stage and provides heat for further production of synthesis gas. Molten slag is removed from the bottom of the gasifier and water quenched. The Stage 1 reaction temperature is about 1700°F, while the Stage 2 temperature is 2700° F. The gasifier operates at 1000-1500 psi (BO-117, FE-068, GR-109, GR-162). Figure 16 schematically shows the BI-GAS system. The gasifier may also be operated with air rather than oxygen at moderate pressures to produce a low-Btu raw gas (BO-117).

The BI-GAS Process was developed by Bituminous Coal Research. After laboratory testing, a 5 lb/hr process and equipment development unit was constructed to test the second stage of the gasifier (GR-162). A 5 ton-per-hour pilot plant has been completed and is in operation (FE-068).

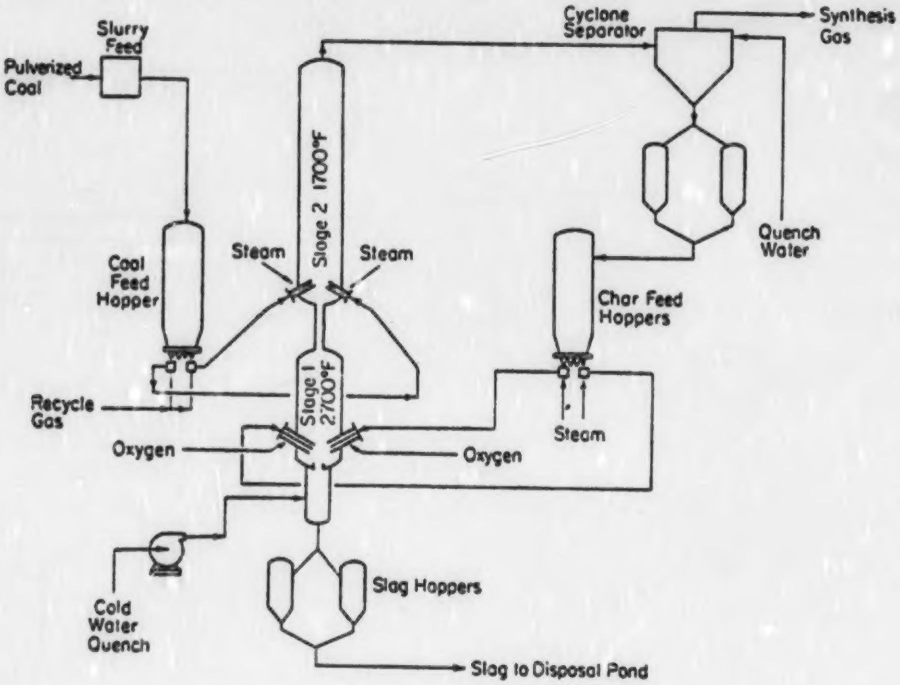
Slurry Feed
Pulverized Coal
Cyclone Separator
Synthesis Gas
Stage 2 1700°F
Steam
Steam
Coal Feed Hopper
Quench Water
Char Feed Hoppers
Recycle Gas
Stage 1 2700°F
Oxygen
Oxygen
Steam
Slag Hoppers
Cold Water Quench
Slag to Disposal Pond

Figure 16. BI-GAS coal gasification process.
(Source KA-124)

CO_2 Acceptor Process

The CO_2 Acceptor Process, specifically developed for lignite and subbituminous coal, is characterized by three fluidized-bed reactors and a circulating system of calcined dolomite. The basic function of this process is to provide heat for the reaction of coal and steam by using an acceptor which reacts exothermally with the CO_2 formed. The product gas stream is then uncontaminated by the products of combustion. The CO_2 Acceptor Process uses the exothermic reaction between calcium oxide (CaO) (obtained from calcined dolomite) and CO_2 to provide the heat of gasification (KA-124). Removal of CO_2 also enhances the exothermic reactions of CO-shift and methanation (BO-117).

Crushed and dried coal, steam, calcined dolomite and synthesis gas are fed to the fluidized-bed devolatilizer. The coal undergoes devolatilization and a steam-carbon reaction. Heat for the formation of CO and H_2 is supplied by the reaction of calcined dolomite with carbon dioxide. The lignite char formed also reacts with hydrogen to form more methane. The synthesis gas exiting the devolatilizer is upgraded downstream into SNG, while the remaining lignite char is sent to the gasifier. Here, more steam and calcined dolomite are added to produce synthesis gas for addition to the devolatilizer. Unreacted char from the gasifier is burned in the regenerator and the heat is used to recalcine the spent dolomite from the gasifier and devolatilizer. The system pressure is 150-300 psi, the gasifier and devolatilizer temperature is 1500° F, and the regenerator temperature is 1900° F (FE-068). This process produces a gas low in carbon dioxide, carbon monoxide, and sulfur. The upgrading procedure is therefore somewhat easier than with some other processes. Figure 17 illustrates the CO_2 Acceptor Process.

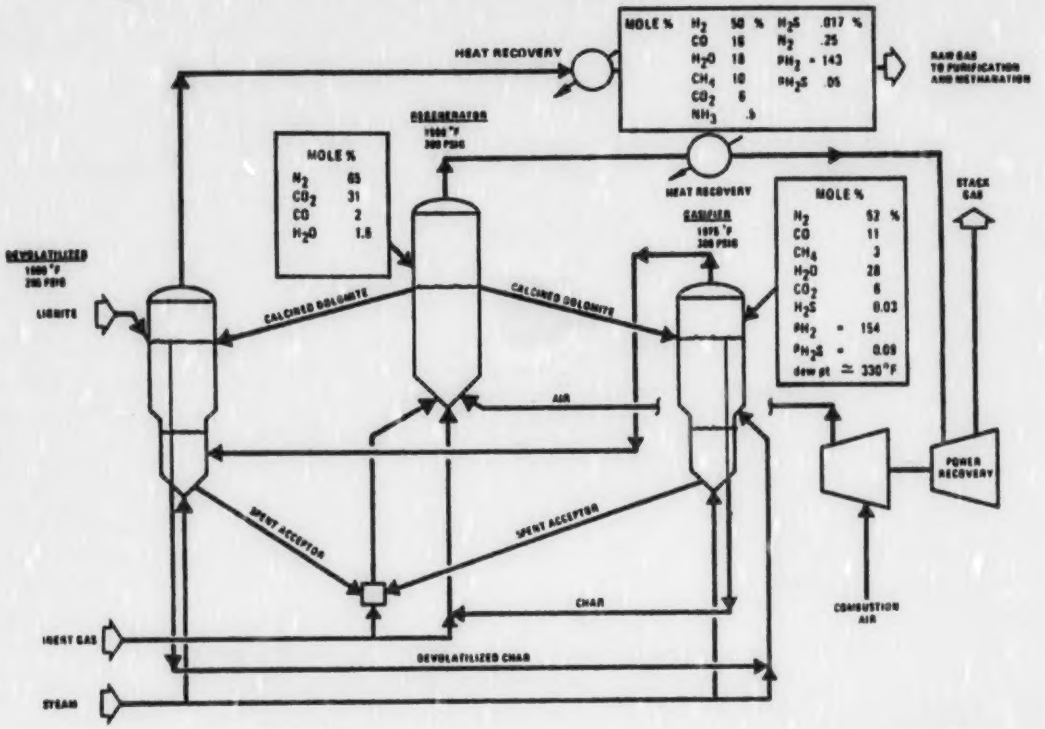
MOLE % H2 50 % CO 16 H2O 18 CH4 10 CO2 6 NH3 .5 H2S .017 % N2 .25 PH2 = 143 PH2S .05
HEAT RECOVERY
RAW GAS TO PURIFICATION AND METHANATION
REGENERATOR
1900 °F
300 PSIG
MOLE % N2 65 CO2 31 CO 2 H2O 1.6
HEAT RECOVERY
STACK GAS
GASIFIER
1575 °F
300 PSIG
MOLE % N2 52 % CO 11 CH4 3 H2O 28 CO2 6 H2S 0.03 PH2 = 154 PH2S = 0.09 dew pt ≃ 330°F
DEVOLATILIZER
1500 °F
290 PSIG
LIGNITE
CALCINED DOLOMITE
CALCINED DOLOMITE
AIR
POWER RECOVERY
SPENT ACCEPTOR
SPENT ACCEPTOR
CHAR
COMBUSTION AIR
INERT GAS
DEVOLATILIZED CHAR
STEAM

Figure 17. CO_2 acceptor process for coal gasification (ST-310).

The CO_2 Acceptor Process was developed by Consolidated Coal Company in conjunction with the Office of Coal Research (OCR) and the American Gas Association (AGA). Bench-scale studies have been completed and a 30 ton per day pilot plant is now in operation. The process is nearing the point of commercial consideration.

Hydrane Process

The Hydrane Process, being developed by the U. S. Bureau of Mines, is designed to produce a high initial methane concentration by the reaction of raw coal with hydrogen.

Pulverized coal of any rank is fed into the first stage of the gasifier which is the coal-hydrogenation reactor or hydrogasifier. A concurrent gas stream from the second stage containing equal parts of methane and hydrogen also enters this chamber which is operated at 1650° F and 1000 psi. The coal devolatilizes and forms some methane. The char then enters the second stage (fluid-bed hydrogenation) reactor where it contacts fresh hydrogen to form more methane. The methane-hydrogen mixture formed in the second stage (char-hydrogenation) reactor flows to the first stage to react with the fresh coal feed. Char from the gasifier's second stage flows to a hydrogen generator where the hydrogen for the process is produced. Since no oxygen is introduced into the gasification system, the only carbon oxides in the gas are those from the oxygen of the coal. The hydrogen is made in a separate reactor by steam-oxygen gasification of the residual char from the fluidized bed. This reduction in carbon oxides simplifies the acid-gas removal and final methanation steps (BO-117, FE-093, KA-124, NA-115, YA-044). The schematic for the Hydrane Process is shown in Figure 18.

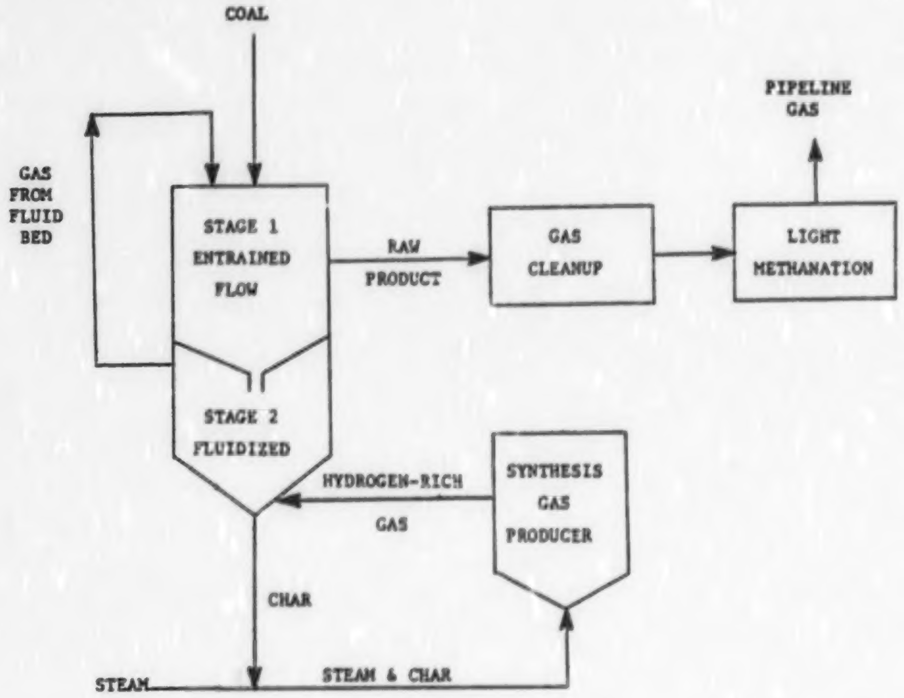
COAL
GAS FROM FLUID BED
STAGE 1 ENTRAINED FLOW
RAW PRODUCT
GAS CLEANUP
LIGHT METHANATION
PIPELINE GAS
STAGE 2 FLUIDIZED
HYDROGEN-RICH GAS
SYNTHESIS GAS PRODUCER
CHAR
STEAM
STEAM & CHAR

Figure 18. Hydrane coal gasification process.

ATGAS Process

The ATGAS Process, developed by the Applied Technology Corporation, is based on the simultaneous carbonization with coal and decarbonization with air or oxygen of a molten iron bath (KA-156).

Crushed coal is injected deeply into a molten iron bath while oxygen is injected near the iron-bath surface. Coal volatiles are cracked into CO and H_2 and released into the off-gas. The remaining carbon dissolves in the bath where it is oxidized with steam and oxygen to yield CO and H_2. A limestone slag floating on the molten iron prevents SO_2 from entering the off-gas. The sulfur in the coal dissolves in the molten iron, diffuses to the slag, and reacts to form calcium sulfide. The slag is continuously withdrawn, desulfurized to yield elemental sulfur, and returned to the gasifier. Operating conditions of the gasifier are about 2600° F and 5 pounds per square inch absolute (psia) (BO-117, KA-124, LA-176, NA-115, US-109).

Figure 19 illustrates the ATGAS process. The process can be adapted to make low-Btu gas by using air instead of oxygen and eliminating the CO-shift and methanation steps. In such a case, the off-gas would go to a power plant boiler for use rather than being upgraded to pipeline quality. The ATGAS process is one of three processes that the Applied Technology Corporation is developing on the basis of molten iron-coal gasification.

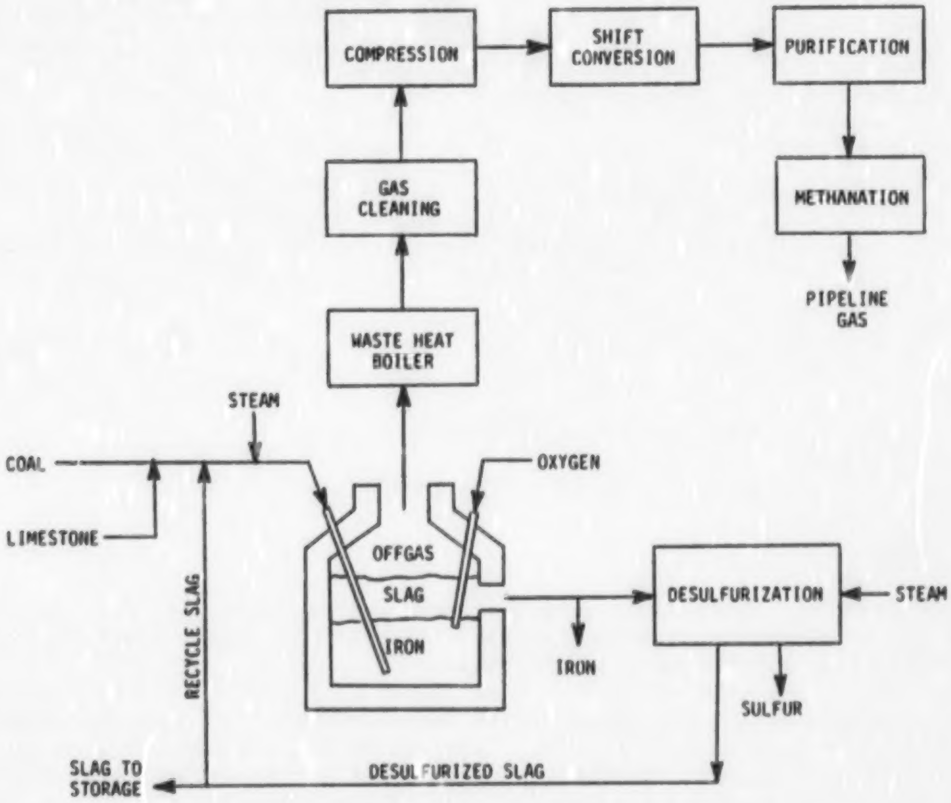
COMPRESSION
SHIFT CONVERSION
PURIFICATION
GAS CLEANING
METHANATION
PIPELINE GAS
WASTE HEAT BOILER
STEAM
COAL
OXYGEN
LIMESTONE
OFFGAS
SLAG
IRON
RECYCLE SLAG
DESULFURIZATION
STEAM
IRON
SULFUR
SLAG TO STORAGE
DESULFURIZED SLAG

Figure 19. Applied Technology Corporation two step gasification system.

Molten Salt Process

The Kellogg Co. Molten Salt Process is based on the gasification of coal in a molten sodium carbonate bath with simultaneous injection of steam and oxygen. The sodium carbonate strongly catalyzes the basic coal-steam reaction permitting essentially complete gasification of coal at a sufficiently reduced temperature to allow appreciable methane production but no tar formation. The molten salt also supplies heat to the coal being gasified. The sulfur in the coal forms sodium sulfide and reaches an equilibrium level at which point the sodium sulfide reacts with carbon dioxide and water to regenerate sodium carbonate and release sulfur in the form of hydrogen sulfide in the gas phase. The hydrogen sulfide can then be scrubbed from the raw gas. The gas leaving the gasifier is processed to recover entrained salt and heat and then further processed for conversion to high-Btu gas. Ash accumulates in the molten salt and leaves the gasifier with a bleed stream of salt that is processed to remove the ash and to recover sodium carbonate for recycling. The bleed stream is quenched with water to dissolve sodium carbonate and the coal ash is removed by filtration. The sodium carbonate solution is carbonated to precipitate sodium bicarbonate ($NaHCO_3$). The bicarbonate is filtered out and calcined to restore the carbonate salt which is then recycled to the gasifier (BO-117, BO-145, CO-193, CO-289, KA-124). Figure 20 illustrates the Kellogg Molten Salt process for high-Btu coal gasification.

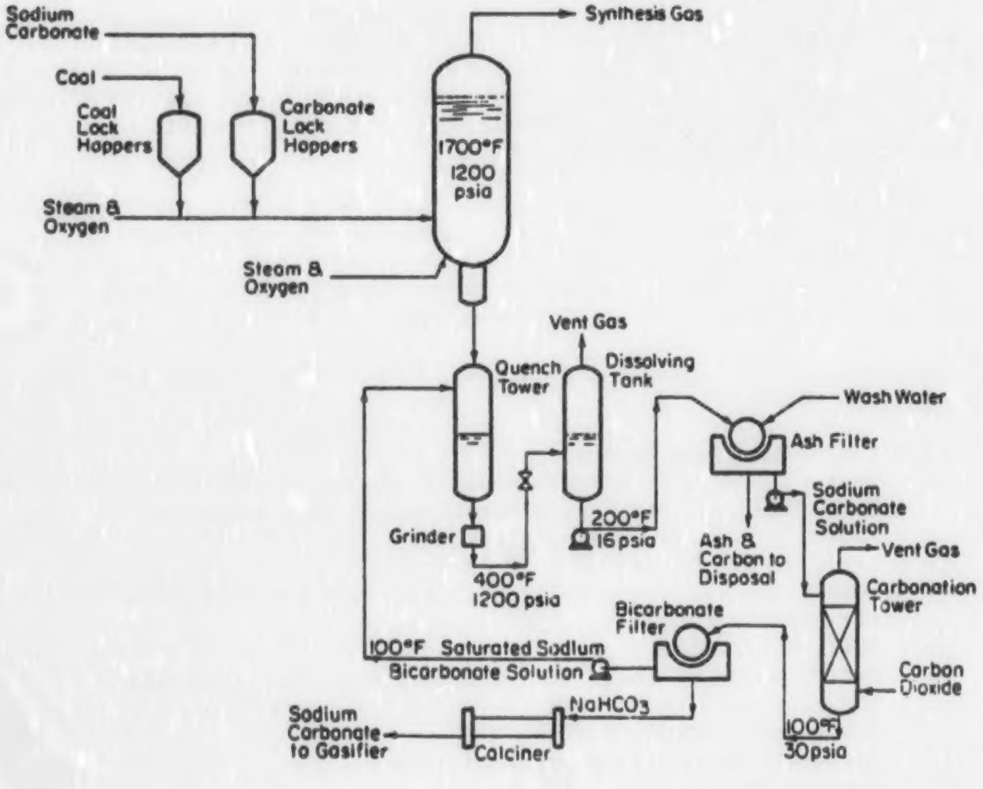
Sodium Carbonate
Synthesis Gas
Coal
Coal Lock Hoppers
Carbonate Lock Hoppers
1700°F
1200 psia
Steam & Oxygen
Steam & Oxygen
Vent Gas
Quench Tower
Dissolving Tank
Wash Water
Ash Filter
Sodium Carbonate Solution
Grinder
200°F
16 psia
Ash & Carbon to Disposal
Vent Gas
Carbonation Tower
400°F
1200 psia
Bicarbonate Filter
100°F Saturated Sodium Bicarbonate Solution
Carbon Dioxide
$NaHCO_3$
Sodium Carbonate to Gasifier
Calciner
100°F
30 psia

Figure 20. Kellogg Molten Salt coal gasification process. (Source: KA-124)

Union Carbide Process

This process being developed by Battelle, Chemico, and Union Carbide is referred to as the Union Carbide Process or as the agglomerating Burner-Gasification Process. This is a pressurized, two stage, fluidized-bed system involving coal or char combusion in one fluidized bed, and steam gasification of coal in a separate fluidized bed. Heat for the carbon-steam reaction is provided by circulating hot coal-ash agglomerates from the burner to the gasifier. Temperature and velocity are regulated so that fly ash is agglomerated in a controlled way into free-flowing, inert solid pellets which provide a moving, direct-contact, heat-transfer medium (CO-208).

Crushed coal and steam enter the lower part of the gasifier. Hot ash agglomerates from the combustor and enters near the top to provide heat for the gasification reaction as it descends through the fluidized bed. The bed is fluidized by steam and gasification products. Part of the ash agglomerated in the bottom of the gasifier is recycled to the combustor. Char is continuously removed from the top of the gasifier and burned with air in the combustor. Raw product gas from the gasifier passes through heat-recovery, purification, and upgrading stages (BO-117, CO-208, KA-124).

COGAS Process

The COGAS Process converts coal to gas and oil products by using a multi-stage, fluidized-bed pyrolysis of coal and the steam reactivity of the char from the pyrolysis. The pyrolysis step is essentially the COED Process which produces gas, oil, and char. The incorporation of an additional step to convert the by-product char to synthesis gas by reaction with steam is the COGAS Progress (BO-117, SE-112).

A gasification-combustion procedure, used in the char gasification, involves burning some char with air in a combustor in order to supply the heat for reactions in the gasifier. Separate pilot plants are testing two versions of the gasification-combustion step. Pyrolysis gas, stripped of light hydrocarbons, is processed along with synthesis gas from the char gasification.

For production of high-Btu gas, the COGAS Process consists of the following eight steps (BL-057):

(1) coal sizing and drying
(2) coal pyrolysis to produce a synthetic crude oil, light hydrocarbons, a gas containing carbon monoxide and hydrogen, and a reactive char
(3) gasification of carbon in product char
(4) compression of raw gases to an intermediate pressure for processing
(5) shift conversion
(6) purification of the combined gases from coal pyrolysis and char-gasification to remove sulfur-containing compounds and carbon dioxide
(7) catalytic methanation to yield high-Btu gas
(8) compression for pipeline use.

EXXON Process

The EXXON Gasification Process is based on the coal-steam reaction in a fluidized-bed gasifier at 1500-1700°F. Heat for the gasification reactions is provided by circulating a stream of hot char. Char is withdrawn from the gasifier, partially burned with air in a char heater, separated from the resulting flue gas, and returned to the gasifier as a direct-contact, heat transfer medium (EP-011, SW-023). The process has been tested on a one-half-ton-per-day unit, but the construction of a 500 ton-per-day gasifier has been deferred. Smaller scale research and engineering studies are continuing.

GRD Process

The GRD Coal Gasification Process is being developed by the Garrett Research and Development Company (GRD) to convert coal into pipeline-quality gas. The process employs an entrained-bed pyrolysis reactor operating at high temperature and low pressure.

Pulverized coal entering the gasifier contacts steam and hot, recycled char. The hot char provides the pyrolysis heat (1500-1700°F) which devolatilizes the entrained coal. The process produces a pyrolysis gas which has a high heating value (600-650 Btu/scf) because of the high direct yield of hydrocarbons. This gas can then be upgraded to high-Btu gas by shift conversion, purification, and methanation. After separation from the pyrolysis gas, part of the char is withdrawn as a solid fuel product. The remainder is partially combusted with air in a combustion unit (gasifier) separated from the combustion gas, and recycled to the gasifier to provide heat (MC-098.

Other Processes

Several other processes are also being investigated as possible sources of high-Btu gas.

Stone and Webster Corporation and Gulf General Atomic Co. are cooperating in a venture to use nuclear reactors to provide heat for hydrogen generation. Coal, slurried in a solvent, is treated with hydrogen to dissolve and hydrocrack it. A pipeline-quality gas is produced without oxygen, steam, or an additional methanation step.

Columbia University is experimenting with the reaction of steam with coal carbon in an electric arc at 10,000°C. Proper reaction and quench conditions produce substitute natural gas (SNG) without an additional methanation step.

With the proper upgrading facilities, such conventional processes as the Koppers-Totzek, Winkler, and Wellman-Galusha processes can be used to produce high-Btu gas.

Low-Btu Gasification Processes

Low-Btu gas is a CO and H_2 rich mixture which is produced from the reaction of coal with steam and oxygen. If air is used as the source of oxygen, a low-Btu gas (150-300 Btu/scf) is produced, whereas if pure oxygen is fed to the gasifier, a medium-Btu gas (300-450 Btu/scf) results. Low-Btu fuel gas is well suited for use in combined cycle power generation facilities.

Once a raw low-Btu gas is produced, it must undergo processing steps to make it usable as a fuel. First, entrained solids and/or liquids must be removed by cooling and/or washing. Following cooling and solids-removal, CO_2 and/or hydrogen sulfide (H_2S) must be removed. In addition to the gas cleaning equipment just described, facilities must also be provided for the treatment of liquid waste streams and recovery of ammonia and hydrocarbon by-products. A typical low-Btu gasification scheme is shown in Figure 21.

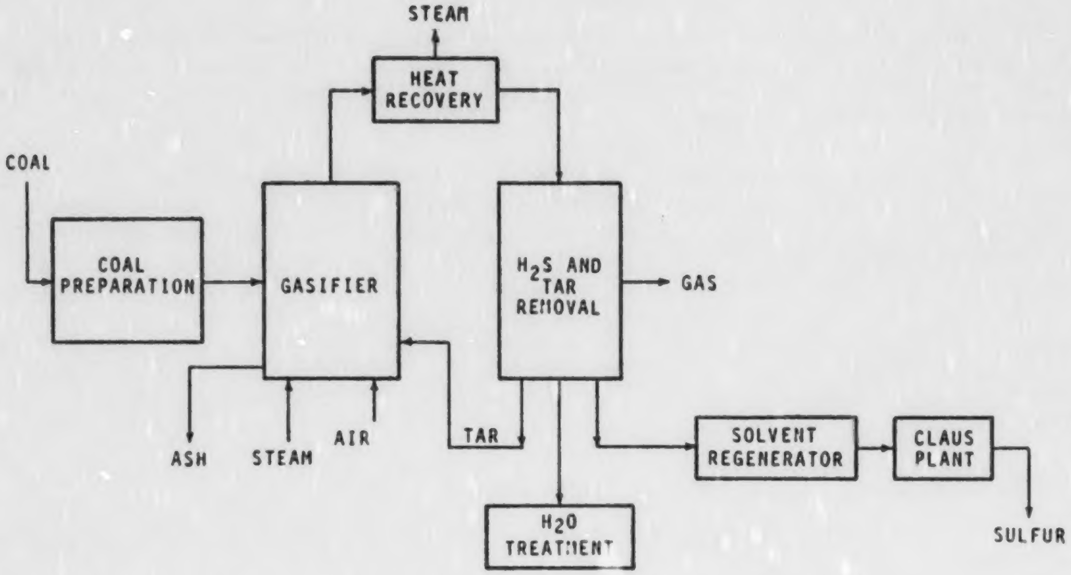

Figure 21. Typical low-Btu gasification diagram.

The major distinguishing feature of the various low-Btu gasification processes is the design of the gasification reactor. In this vessel, coal reacts with oxygen to produce a raw gas rich in CO and H_2 which can be purified and used as a boiler fuel. The difference among the processes are found in the operating temperatures, pressures and mechanical characteristics of the gasifier.

A large number of low-and intermediate-Btu gasification processes are being studied. Many of these are still in the developmental stage. Available information on the status of various low-Btu gasification processes is summarized in TABLE 5.

Lurgi Process

The Lurgi gasifier is the same for both high-and low-Btu gasification. The main differences in the processes are that for low-Btu gasification, air is substituted for oxygen and upgrading facilities are not used.

TABLE 5. LOW-BTU COAL GASIFICATION TECHNOLOGY

PROCESS NAME AND DEVELOPER	DEVELOPMENT STATUS	DEVELOPMENT PLANS
Lurgi Lurgi Mineralotechnik G.m.b.H.	Process widely used to make synthesis gas and fuel gas.	Synthesis gas for SNG production.
Koppers-Totzek Koppers-Totzek Co.	Feedstock for ammonia synthesis.	Upgrading of synthesis gas to pipeline gas.
Winkler Davy Powergas Co.	Synthesis gas production, commercially proven.	
Wellman-Galusha McDowell Wellman Co.	Commercially proven synthesis gas production.	
BOM Producer Gas U.S. Bureau of Mines	Pilot plant gasifier 42 inches in diameter in operation.	Cooperative efforts with G.E. and TVA.
U-Gas® Institute of Gas Technology	Small pilot plant with 1 ft diameter reactor.	Design underway for pilot plant.
Entrained Gasifier Combustion Engineering Co.	Preliminary tests completed	Operation of 120 tpd pilot unit.
GEGAS General Electric Co.	Tested at 50 lb/hr rate.	Operation of 12 tpd pilot unit.
HRI Process Hydrocarbon Research, Inc.	Concept developed at City University of New York.	Operation of 10 tpd pilot unit.
PAMCO Gasification Bituminous Coal Research, Inc.	Construction of 100 lb/hr development unit.	
Molten Salt Process Rockwell International Corp./ Atomics-International Division	Tested in 200 lb/hr pilot unit at 1 atm.	Construction of 120 pilot plant.
Unnamed Westinghouse Electric Corp.	Construction of 15 tpd pilot unit.	Construction of 55 tpd pilot plant and combined cycle demonstration facility.
Unnamed Foster Wheeler Energy Corp.		Construction of 36 megawatts gasification combine cycle pilot plant
Unnamed Babcock and Wilcox Co.	Tested in experimental unit.	

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Koppers-Totzek Process

The Koppers-Totzek gasifier is a single stage, entrained flow, ash slagging gasifier capable of treating all types of coal. Pulverized coal is fed to the gasifier with steam and air through coaxial burners at each end of the gasifier. The reaction temperature at the burner discharge is about 3300°F. At this temperature the components react instantaneously to produce carbon monoxide, hydrogen, and molten slag. No tars, condensable hydrocarbons, or phenols are formed. Part of the coal ash is removed from the bottom of the gasifier as molten slag. The remaining ash exits with the raw gas through the top of the gasifier. The gas is water-quenched to solidify entrained molten ash, passed through a waste-heat boiler, scrubbed to remove entrained solids, and purified to remove hydrogen sulfide and carbon dioxide (BO-117, FA-097, KA-124, RA-150). Figure 22 illustrates the Koppers-Totzek process.

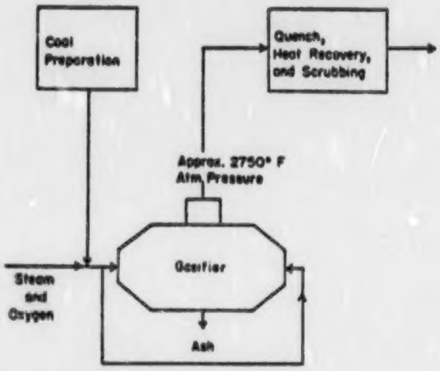

Figure 22. Koppers-Totzek coal gasification process.
(Source: UN-025)

Winkler Process

The Winkler gasifier is a fluid bed, steam-air gasifier. Crushed coal is dried and fed by screw conveyors to the gasifier. The coal undergoes reactions to yield a raw gas rich in CO and H_2. The gasifier reaction temperature is 1500-1850°F and the pressure is about atmospheric. Thirty percent of the coal ash is removed from the bottom of the gasifier while about 70 percent is carried overhead with the raw gas. Above the fluid bed, additional steam and air are injected to react with the remaining carbon. The resultant gas is processed and utilized. Air, rather than oxygen, is used for low-Btu gas applications (BA-329, BO-117, DA-108, RA-150). Figure 23 illustrates the Winkler process.

Wellman-Galusha Process

The Wellman-Galusha gasifier (Figure 24) is a moving bed, steam-air gasifier. Crushed coal is fed to the gasifier through a lock hopper and distributed over the coal bed by a rotating arm. The coal bed moves downward

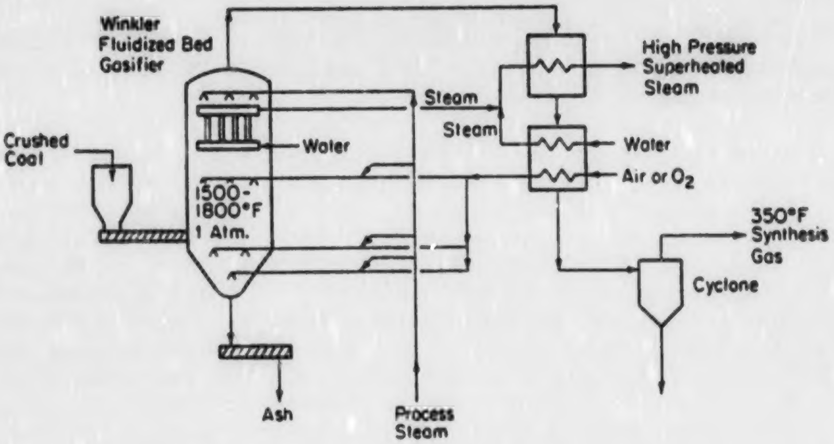
Winkler Fluidized Bed Gasifier
Crushed Coal
Water
1500-1800°F
1 Atm.
Steam
Steam
High Pressure Superheated Steam
Water
Air or O_2
350°F Synthesis Gas
Cyclone
Ash
Process Steam

Figure 23. Winkler coal gasification process. (Source: KA-124)

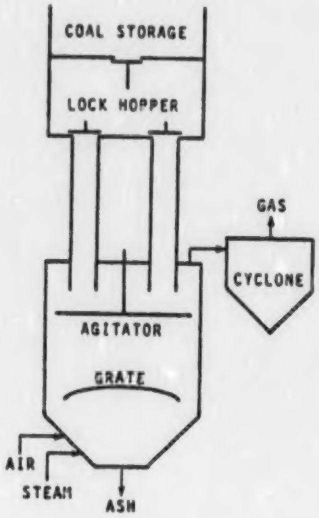
COAL STORAGE
LOCK HOPPER
GAS
CYCLONE
AGITATOR
GRATE
AIR
STEAM
ASH

Figure 24. Wellman-Galusha gasifier process. (Source: ZA-042)

through the gasification zone, forming char and some methane. As the resulting char leaves the gasification zone and enters the combustion zone, it contacts steam and oxygen from air injected at the bottom of the gasifier and forms CO and H_2. A revolving eccentric grate at the bottom of the gasifier allows for bed support and ash removal. A rotating agitator arm, located just below the coal bed, is used when handling slightly caking coals. Strongly caking coals must be pretreated to destroy their caking tendencies before gasification can be accomplished. The low-Btu gas flows countercurrently to the coal bed and is removed from the top of the gasifier at approximately 1250°F. The gasifier operates at essentially atmospheric pressure (BA-260, RA-150).

U-GAS® Process

The U-GAS® process, developed by the Institute of Gas Technology, uses an ash-agglomerating, fluidized-bed gasifier to produce a clean gas with a heating value of about 140 Btu/scf.

Crushed coal is fed to the gasifier from a lock hopper. Coals with caking tendencies are first pretreated with air at 800° F in a separate vessel. Partial oxidation of the coal destroys its caking properties, and the pretreated coal and gas flow into the fluid-bed gasifier operating at 35 psi and 1900° F. Air and steam, injected into the bottom of the gasifier, react with the coal to form the synthesis gas. The ash agglomerates, settles to the bottom, and is removed through lock hoppers. Gases produced in the pretreater and gasifier are combined and passed through cyclones where coal fines are removed and returned to the gasifier. The raw gases then pass through a heat recovery system, a sulfur removal system, and a power recovery turbine before being used as a low-Btu gas (BO-117, KA-124, LO-115). The U-GAS® process is shown in Figure 25.

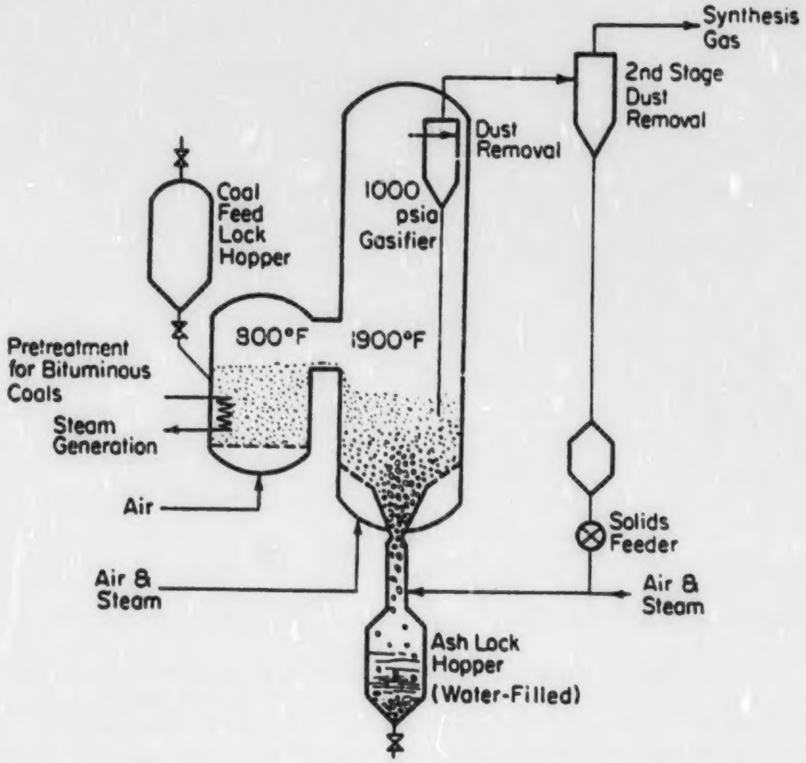
Synthesis Gas
2nd Stage Dust Removal
Dust Removal
Coal Feed Lock Hopper
1000 psia Gasifier
800°F
1900°F
Pretreatment for Bituminous Coals
Steam Generation
Air
Air & Steam
Solids Feeder
Air & Steam
Ash Lock Hopper (Water-Filled)

Figure 25. U-GAS® process. (Source: KA-124)

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GEGAS Process

The General Electric Co. (GEGAS) Process employs a fixed bed gasifier. A unique feature of the process is the injection of coal into the high-pressure gasifier by extrusion. This procedure allows coal fines to be compacted with a tar binder into a solid bar which is injected into the gasifier and chopped into chunks under pressure. The extrusion process eliminates gas losses associated with lock hoppers, allows the gasifier to operate at high pressures, and solves some of the problems caused by coal fines. Another unique feature of the process is the use of liquid membranes for acid gas removal (BU-173, GE-069).

Westinghouse Process

The Westinghouse Process is a two-stage, fluidized-bed process. The fluidized-bed subsystems are the devolatilizer/desulfurizer and the gasifer/agglomerator. Air, steam, and coal react in the gasification process and sulfur is removed from the high temperature gases with a limestone sorbent (Figure 26).

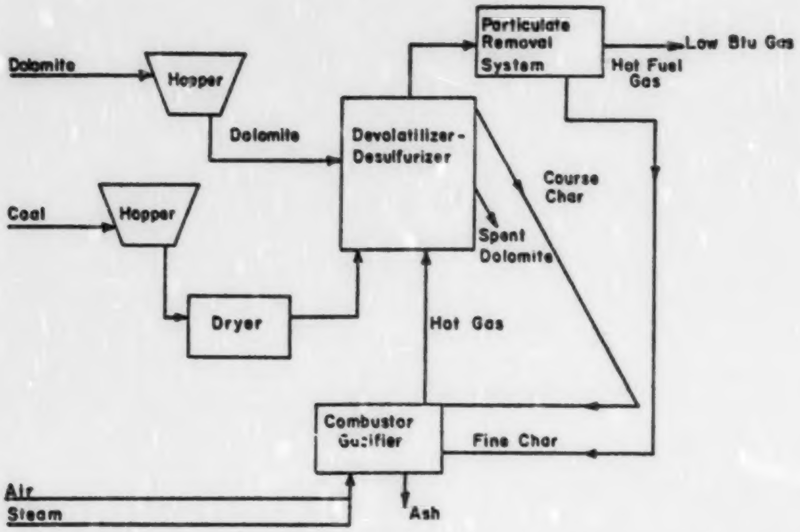
Particulate Removal System
Low Btu Gas
Hot Fuel Gas
Dolomite
Hopper
Dolomite
Devolatilizer-Desulfurizer
Course Char
Coal
Hopper
Spent Dolomite
Dryer
Hot Gas
Combustor Gasifier
Fine Char
Air
Steam
Ash

Figure 26. Westinghouse fluidized-bed coal gasification process. (Source: UN-025)

Crushed coal is fed into the bottom of the devolatilizer/desulfurizer at 1600-1800° F. Devolatilization, desulfurization, and partial hydrogasification produce gas and char. Sulfur is removed by the reaction of limestone or dolomite with hydrogen sulfide in the fuel gases to form calcium sulfide. The char is withdrawn and transferred to the gasifier/agglomerator where the char is gasified with air and steam at 2100° F. Ash agglomerates at this temperature and is removed from the system. Reactions in this vessel provide the process heat. The hot gases produced in the gasifier/agglomerator are introduced into the devolatilizer/desulfurizer. The raw product gas from the devolatilizer/desulfurizer passes through a cyclone to remove fines (AR-055, BO-117, HO-238).

U.S. Bureau of Mines Stirred Fixed-Bed Process

This U.S. Bureau of Mines Process employs a fixed-bed gasifier that has a stirrer mounted in the center (Figure 27). The stirrer both rotates and moves vertically to prevent any caking. Crushed coal is fed into the top of the reactor and falls onto a rotating grate. Steam and air enter below the grate and ash is removed at the bottom. The stirred fixed bed gasifier is essentially a modified Lurgi gasifier that allows strongly caking coals to be used (KA-124).

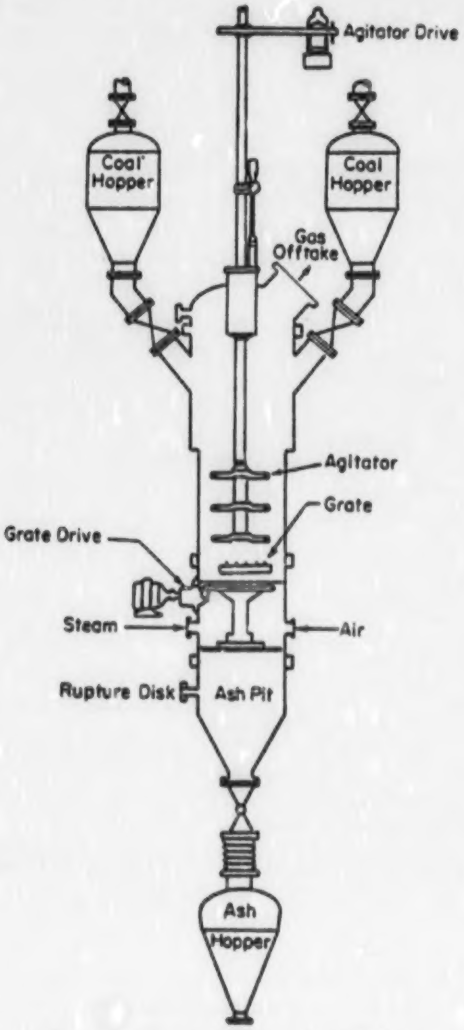
Agitator Drive
Coal Hopper
Coal Hopper
Gas Offtake
Agitator
Grate
Grate Drive
Steam
Air
Rupture Disk
Ash Pit
Ash Hopper

Figure 27. U.S. Bureau of Mines gasifier. (Source: KA-124)

Other Processes

Hydrocarbon Research, Inc. is developing a conical, fluidized-bed gasifier. This process uses a high, superficial gas velocity which allows the gasifier to operate at temperatures above the ash softening point (2200-2300° F).

In addition to BI-GAS, Bituminous Coal Research, Inc. is also developing a multiple fluidized-bed gasification process that yields a gas stream free of liquids. The Btu content of the product gas depends on whether air or oxygen is fed into the system with the steam and coal.

Combustion Engineering Company is developing a process in which pulverized coal is entrained in air and steam for feeding to a gasifier which will operate at 1 to 10 atmospheres. The gasifier is comparable to a pulverized coal-fired boiler with similar fuel injection, gas flow patterns, and heat exchange surfaces. The gasifier, however, has a two-level firing arrangement in which recycled char is fired through combustor nozzles of the lower zone and in which fresh coal, steam, and air are injected through reductor nozzles. Gasification occurs in the upper zone (KA-124).

The Atomics International Division of Rockwell International Company developed a process in which coal contacts air but no steam in a molten sodium carbonate bath at about 1800° F and 5 to 10 atmospheres. The basis of the process is oxidation of carbon to carbon monoxide and partial pyrolysis and distillation of volatile material. Sulfur and ash are removed via the molten salt.

The Kellogg Company has a molten salt process for producing low-Btu gas. The gasification step is similar to that for high-Btu gas but the low-Btu process uses air instead of oxygen and requires no steam.

Submerged Coal Combustion and PATGAS are two processes developed by the Applied Technology Corporation. Both processes use a gasifier with a molten iron bath. PATGAS is similar to ATGAS but uses air instead of oxygen and requires no shift conversion or methanation. The Submerged Coal Combustion process gasifies coal with air and does not use steam.

Foster Wheeler Energy Corporation is designing and developing a two-stage, air blown, pressurized, entrained flow, slagging gasifier. The gasifier operating at 1800° F will produce low-Btu gas for use in a combined-cycle power generating system.

Under the proper operating conditions, low-Btu or intermediate-Btu coal gasification can be obtained from other previously described processes such as BI-GAS, Synthane, HYGAS, Garrett pyrolysis, and Columbia University processes.

COAL LIQUEFACTION

Coal liquefaction is the conversion of coal into clean, synthetic hydrocarbon liquids.

Liquefaction processes may be separated into two basic groups: (1) processes relying solely on heat to crack the coal (carbonization processes) and (2) processes providing hydrogen in some form to facilitate the dissolution of the coal. The appeal of carbonization processes is the apparent simplicity involved with just heating the coal. The advantage of adding hydrogen is that the amount of liquid product is not limited by the low hydrogen content of the coal.

Processes utilizing hydrogen can be classified according to how the hydrogen is added. Three types of coal liquefaction utilizing hydrogen are: (1) direct hydrogenation processes, (2) solvent hydrogenation processes, and (3) gasification-synthesis processes.

Common Technology

Much common technology is used in the different liquefaction processes. Most coal liquefaction processes differ in the reaction or dissolution step where new technology is involved. Apart from the reaction step, the operations associated with coal liquefaction are accomplished with existing technology. Coal processing prior to the reaction consists of essentially the grinding and drying procedures used in the coal industry, whereas gas/liquid processing (after reaction) is accomplished with conventional petroleum refining techniques. The general processing steps are (1) coal preparation, (2) reaction and solid separation, (3) fractionation, (4) gas recovery and treating, (5) sulfur recovery, (6) naphtha or light oil hydrotreating, and (7) heavy oil hydrotreating. In addition to these main processing steps, a liquefaction plant will have many auxiliary operations, including power generation, ammonia separation, and water treatment facilities.

Steps in coal liquefaction processes where common processing is utilized are (1) coal preparation, (2) gas-liquid separation, (3) acid gas removal and sulfur recovery, (4) liquid product separation, and (5) product desulfurization.

In addition to these similarities, processes which add molecular hydrogen (direct hydrogenation and solvent hydrogenation) have the same basic steps throughout the dissolution process. Areas of similarity among these processes are as follows:

(1) coal preparation

(2) slurrying coal

(3) preheat and dissolution

(4) cooling and removal of gases

(5) pressure let-down and removal of vapors

(6) separation of solids

(7) gasification of char

(8) hydrotreating filtrate

(9) separation of products and solvent for recycle.

The gasifier in these processes serves the two-fold purpose of complete utilization of solids, and hydrogen production for the dissolution step.

Areas in which problems exist for coal liquefaction processes are as follows: (1) thermal efficiency, (2) water management, (3) solids separation, (4) solvent-to-coal ratio, (5) solvent generation, (6) preheating, (7) pressure let-down, and (8) hydrogen production.

Liquefaction Processes

TABLE 6 lists and summarizes the level of development of various liquefaction processes.

The main differences in coal liquefaction occur in the dissolution or reaction step. Due to the various conversion processes which may be utilized (direct hydrogenation, solvent hydrogenation, gasification-synthesis, and carbonization), the reactors may differ considerably. Reactors employed in liquefaction processes include open vessels, stirred vessels, fixed beds, and fluidized beds. Operating conditions change according to reaction mechanisms and reactor types. Solid handling facilities and miscellaneous support facilities also depend upon the reaction procedure employed.

The following descriptions of liquefaction processes are divided into hydrogenation and pyrolysis processes.

Hydrogenation Processes

Direct hydrogenation processes feed a stream containing molecular hydrogen into the reactor with a coal slurry.

Solvent hydrogenation, another kind of coal liquefaction process, physically dissolves coal in a recycled hydrocarbon solvent. Coal dissolution allows removal of insoluble ash and insoluble sulfur from the extract. Any hydrogenation that occurs during extraction also converts soluble organic sulfur to a removable form. The coal extract is processed to remove ash, sulfur, and other impurities; to recover solvent; and possibly to further hydrogenate and purify the liquid product.

Some overlap can exist between direct hydrogenation and solvent hydrogenation processes since direct hydrogenation processes use a recycled solvent to slurry the coal to the reactor.

Gasification-synthesis processes produce liquid fuels by first gasifying the coal and then converting the gas to a liquid by a Fischer-Tropsch synthesis. The hydrogen is introduced into the system as steam to the gasifier.

H-Coal® Process

The H-Coal® Process, jointly developed through the efforts of Hydrocarbon Research, Inc. (HRI) and the Office of Coal Research (OCR), is carried out in an ebullated bed reactor in the presence of hydrogen and a cobalt molybdate catalyst. The ebullated bed reactor is the heart of the process. The

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TABLE 6. COAL LIQUEFACTION TECHNOLOGY

Process Name & Developer	Development Status	Development Plans
Solvent Refined Coal (SRC) Pittsburgh and Midway Coal Mining Co.	Tested on 6 tpd pilot plant.	Construction and operation 50 tpd pilot plant.
Consol Synthetic Fuel Process Consolidation Coal Company	Tested on 20 tpd pilot plant.	
Char Oil Energy Development (COED)	Tested on 36 tpd pilot plant.	Word directed toward utilization of char; pilot plant to test COGAS process for gasification of COED char.
H-Coal® Hydrocarbon Research, Inc.	Tested on 3 tpd pilot plant.	Construction and operation of 600 tpd pilot plant.
Synthoil U.S. Bureau of Mines	Tested on ½ tpd pilot plant.	Construction and operation of 8 tpd pilot plant.
Gulf Catalytic Coal Liquids Gulf Research & Development	Tested on 120 lb/day bench scale.	Construction and operation of 1 tpd pilot plant.
Garrett Flash Pyrolysis Process Garrett Research & Development Co.	Tested on 3½ tpd pilot plant.	
Lurgi-Ruhrgas Lurgi-Ruhrgas	Operated 1600 tpd unit.	
UOP Universal Oil Products Co.	Tested on small scale.	
EXXON Solvent Donor Process EXXON Corporation	1½ tpd pilot plant.	300 tpd demonstration plant.
TOSCOAL The Oil Shale Corporation	Tested on 25 tpd pilot plant.	
Zinc Halide Process Conoco		Bench scale testing of 100 lb/hr process development unit.
Clean Coke Process U.S. Steel Corporation	Certain process components tested on ½ tpd scale.	Construction and operation of 10 tpd pilot plant.

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fluidized bed concept allows a catalyst to be used without the plugging problems inherent with a fixed bed reactor (JO-135).

A flow diagram for the H-Coal® Process is shown in Figure 28. Ground coal is slurried with a recycled solvent, mixed with hydrogen, and routed through a preheater to the reactor. Upward passage of the coal and reaction products maintains the catalyst in a fluidized state. Unreacted solids are removed at the top of the reactor along with the liquid product but the coarser catalyst is retained in the reactor. The catalyst can be added and withdrawn continuously in order to maintain catalytic activity. Turbulence is insured by an internal slurry recycle. The reactor operation at 800-900° F and at 1500-3000 psig. Solids separation is accomplished by hydrocyclones followed by a rotary drum filter. Conversion for the bituminous coal is at 89.3 weight percent (wt.%) and conversion for the subbituminous coal is at 81.4 wt.%. Products typically would be a naphtha and a fuel oil (JO-135, KA-124).

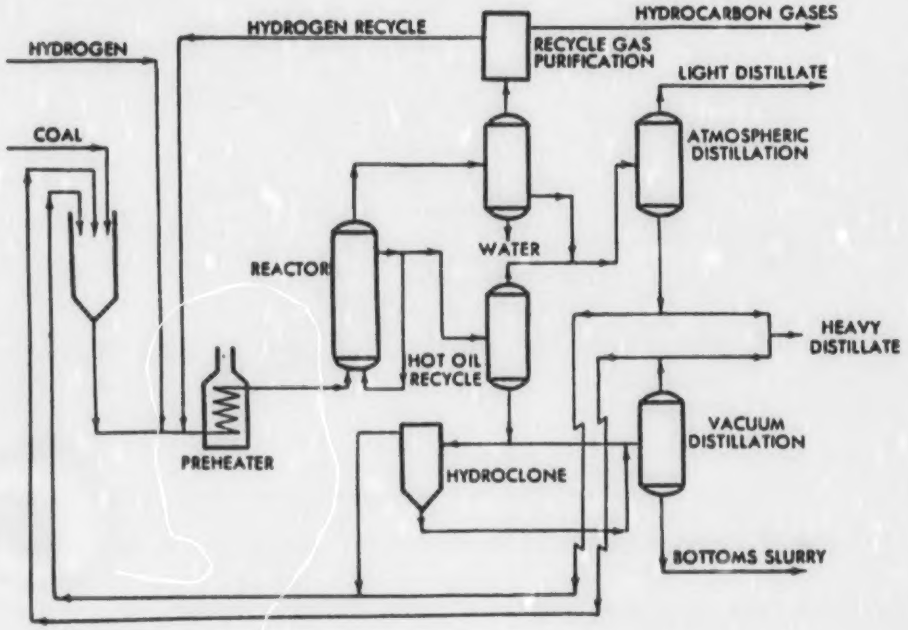
HYDROCARBON GASES
HYDROGEN RECYCLE
HYDROGEN
RECYCLE GAS PURIFICATION
LIGHT DISTILLATE
COAL
ATMOSPHERIC DISTILLATION
WATER
REACTOR
HEAVY DISTILLATE
HOT OIL RECYCLE
VACUUM DISTILLATION
PREHEATER
HYDROCLONE
BOTTOMS SLURRY

Figure 28. H-Coal® Process for fuel oil production--devolatilization plant. (Source: ST-310)

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Synthoil

The Synthoil Process pilot plant, operated by the U.S. Bureau of Mines, employs a direct hydrogenation process. A slurry of coal and recycle solvent is mixed with hydrogen, preheated, and injected into the reactor. The reactor contains a fixed bed packed with pellets of a cobalt molybdate catalyst. The reactor is normally operated at 840° F and 2000-4000 pounds per square inch gage (psig). Over 90% of the coal is dissolved. The turbulent flow of hydrogen and short residence time prevents the coal from excessive plugging of the catalyst bed. The coal is converted to a heavy hydrocarbon liquid and the sulfur is eliminated as hydrogen sulfide. The product liquids, solids, and gases are separated. The solids are sent to a pyrolizer which yields more fuel oil and a carbonaceous residue. This residue is fed to a steam-oxygen gasifier to produce make-up hydrogen for the process. The gas stream is purified to remove ammonia, hydrogen sulfide, water, and gaseous hydrocarbons. The purified hydrogen is combined with fresh hydrogen and returned to the reactor (AK-011, AK-014, YA-040). A flow diagram of the Synthoil Process is shown in Figure 29. The degree of hydrogenation determines the product characteristics and uses.

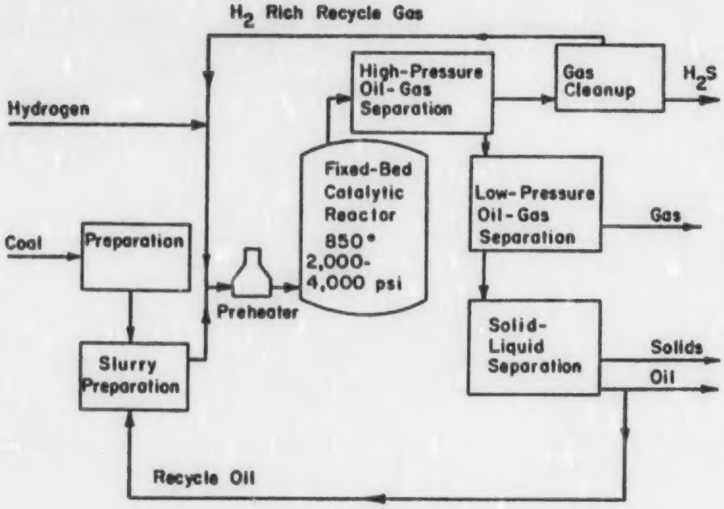
H_2 Rich Recycle Gas
Hydrogen
High-Pressure Oil-Gas Separation
Gas Cleanup
H_2S
Fixed-Bed Catalytic Reactor 850° 2,000-4,000 psi
Low-Pressure Oil-Gas Separation
Gas
Coal
Preparation
Preheater
Slurry Preparation
Solid-Liquid Separation
Solids
Oil
Recycle Oil

Figure 29. Synthoil coal liquefaction process. (Source: UN-025)

Gulf Catalytic Coal Liquefaction

Another direct hydrogen process is Gulf Catalytic Coal Liquefaction, developed by Gulf Research and Development Company. The process uses a fixed-bed, catalytic reactor designed to avoid plugging. Ground coal is slurried with a recycle solvent, is mixed with hydrogen, and then passes through a preheater to the reactor. Reactor conditions are 800-900° F and 3000 psig. Approximately 91% of the coal is dissolved. The product goes to a gas-liquid separator where hydrogen is recovered for recycling. Solid separation is achieved with hydrocyclones followed by rotary filters. Approximately 75%

of the product is a heavy fuel oil with the remaining 28% being equivalent to a distillate fuel cut. A flow diagram of the Gulf process is shown in Figure 30. This process routes the filter cake to a coker rather than to a gasifier. Hydrogen production is accomplished with a steam-hydrocarbon reformer (GU-049, KA-124, MA-398, MC-112, RA-150).

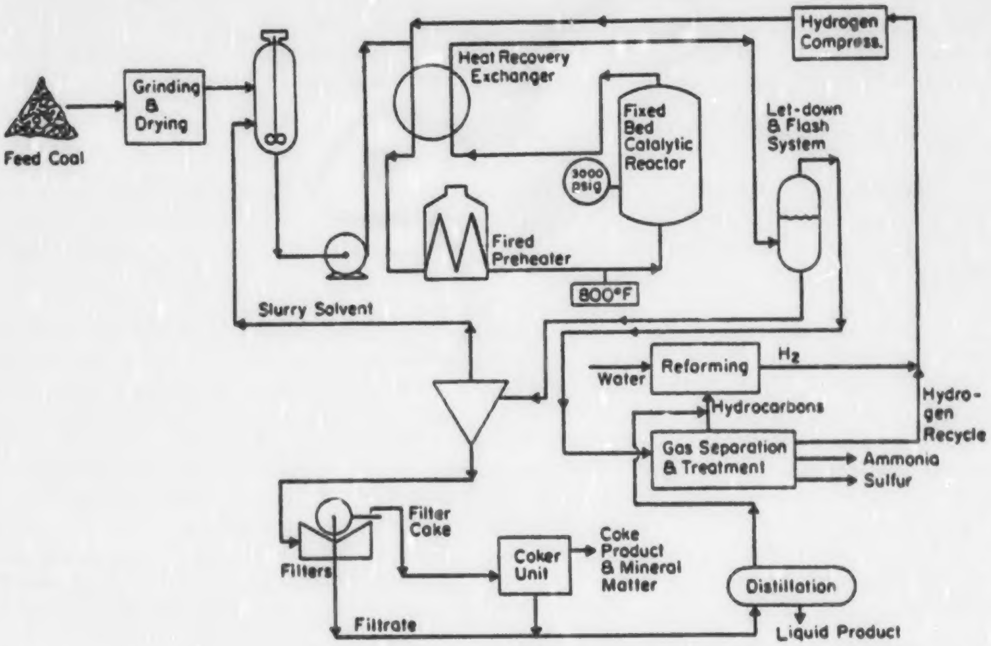
Hydrogen Compress.
Heat Recovery Exchanger
Grinding & Drying
Feed Coal
Fixed Bed Catalytic Reactor
3000 psig
Let-down & Flash System
Fired Preheater
800°F
Slurry Solvent
Reforming
Water
H2
Hydrocarbons
Hydro-gen Recycle
Gas Separation & Treatment
Ammonia
Sulfur
Filter Cake
Filters
Coker Unit
Coke Product & Mineral Matter
Distillation
Filtrate
Liquid Product

Figure 30. Gulf catalytic coal liquids process. (Source: KA-124)

EXXON Solvent Donor

The EXXON Solvent Donor Process employs a catalyst and donor solvent. Crushed coal is slurried with recycle solvent, preheated to 800° F, and pumped into the liquefaction reactor (2000 psig). Preheated hydrogen is also added to the reactor. The product is then separated by distillation into gas, naphtha, recycled solvent, distillate, and unconverted coal and ash. The recycled solvent is hydrogenated catalytically and slurried with fresh coal. The raw liquid product is upgraded by hydrogenation. The heavy bottoms and solids go to a gasifier for hydrogen production (SW-023).

UOP Coal Liquefaction

Universal Oil Products Company is developing a coal liquefaction process that will yield four barrels of liquid product per ton of high sulfur coal. Pulverized coal is mixed with a solvent and hydrogen and is piped to a reactor operating at high temperatures and pressures. Ash is separated and the resulting hydrocarbon stream is catalytically hydrotreated. Usable gas by-products including light hydrocarbons are also formed.

Coalcon

Coalcon Company is a joint venture of Union Carbide and Chemico to build a coal-to-clean-fuels demonstration plant. The plant is designed to use a hydrocarbonization process to convert 2,600 tons of coal per day into 3,990 barrels of liquid product and 22 million cubic feet of pipeline-quality gas. Pulverized coal is preheated and then hydrogenated in a hydrocarbonization vessel at modest pressure. The products are cooled and separated. The gases are purified to yield methane and other light hydrocarbon fuels. The char is gasified with oxygen in an agglomerating bed unit to produce make-up hydrogen.

Solvent Refined Coal

Pittsburgh and Midway Coal Mining Company's Solvent Refined Coal Process (SRC) was originally developed to produce a de-ashed and desulfurized solid for power plant fuel. Recent work has modified the process to yield liquid products.

Coal is pulverized and mixed with a recycled solvent similar to anthracene oil. The slurry, typically 2 to 3 parts solvent with 1 part by weight coal, is mixed with hydrogen and routed to the reactor. Reactor conditions are approximately 850° F and 1050 psig. The SRC process differs from the other direct hydrogenation processes in that no catalyst is employed in the reactor. The reactor consists of four vertical tubes in series with upflow of both liquid and gas. Initially, the solvent is absorbed by the coal resulting in a significant increase in slurry viscosity. As the residence time of the coal increases, dissolution begins to occur. Over 90% of the coal is dissolved. Solid separation is accomplished by rotary drum filters. A flow diagram of the SRC process is shown in Figure 31. Liquid products consist of a naphtha, fuel oil, and a residual oil (RA-150).

Consol Synthetic Fuel

The Consol Synthetic Fuel (CSF) process uses a coal liquefaction scheme designed by the Consolidation Coal Company. It is a solvent extraction process combined with a catalytic hydrogenation step (UN-025). Figure 32 is a diagram of the CSF process.

The Consol process employs a hydrogen donor solvent to dissolve the coal. Feed coal is dried and crushed in a coal preparation step, slurried with the recycled solvent, and fed through the preheater to the reactor. Only solvents capable of transferring hydrogen are effective for dissolution of the coal. The reaction takes place in a stirred vessel. Since turbulence cannot be provided by the H_2 gas stream, the agitation is needed to insure the presence of the hydrogen donor solvent whenever a coal molecule is cracked. The reactor operating conditions are 700-750° F and 400 psig. Approximately 80% of the coal is dissolved (KA-124).

Vapors produced in a stirred extraction vessel are sent to a fractionation section. Unreacted coal and the liquid product are separated in hydrocyclones. Liquid passes to the fractionation section and solids to a carbonization unit. After removal of light ends and solids from the reactor effluent the liquid stream must be hydrotreated. The hydrotreating step not only

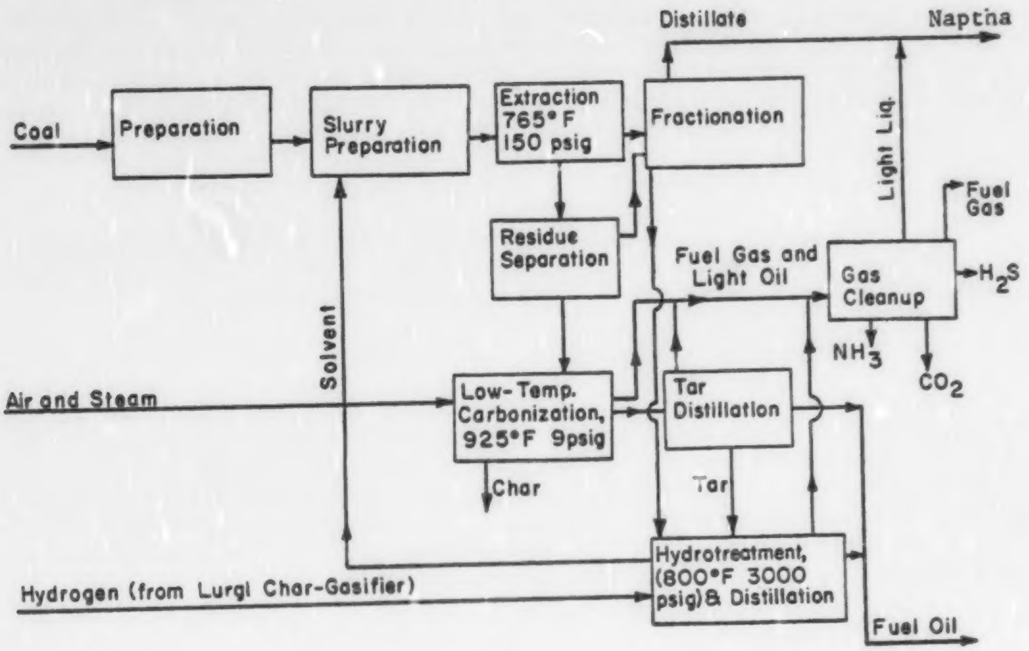
Coal
Preparation
Slurry Preparation
Extraction 765°F 150 psig
Fractionation
Distillate
Naptha
Light Liq.
Fuel Gas
Residue Separation
Fuel Gas and Light Oil
Gas Cleanup
H2S
NH3
CO2
Solvent
Air and Steam
Low-Temp. Carbonization, 925°F 9psig
Tar Distillation
Char
Tar
Hydrotreatment, (800°F 3000 psig) & Distillation
Hydrogen (from Lurgl Char-Gasifier)
Fuel Oil

Figure 31. Solvent refined coal process. (Source: UN-025)

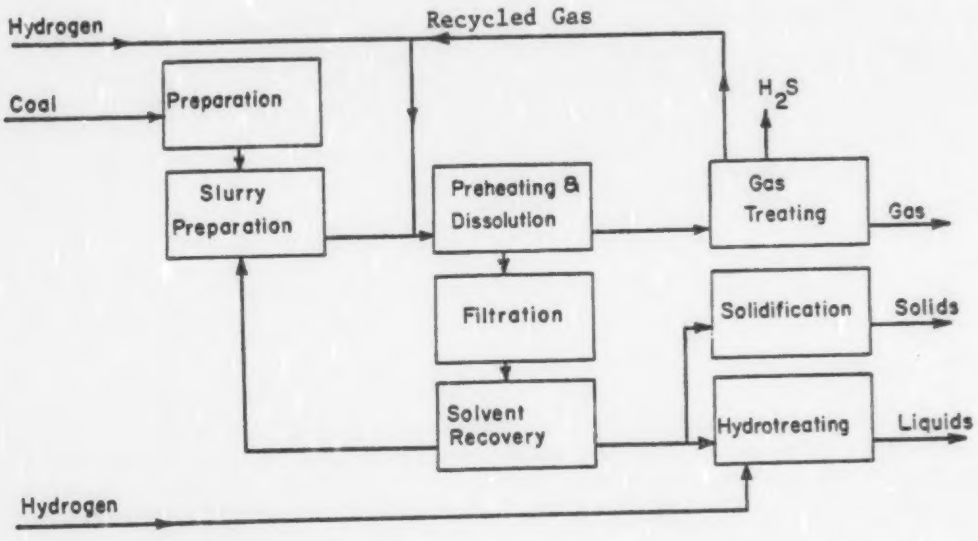
Hydrogen
Recycled Gas
Coal
Preparation
H2S
Slurry Preparation
Preheating & Dissolution
Gas Treating
Gas
Filtration
Solidification
Solids
Solvent Recovery
Hydrotreating
Liquids
Hydrogen

Figure 32. Consol synthetic fuel process. (Source: UN-025)

desulfurizes what will be the product streams but, by partial hydrogenation, regenerates the recycle solvent. Hydrogenation is achieved in a fixed bed reactor containing cobalt molybdate catalyst, operating at 775-850° F and at 3000-4200 psig. Hydrogen for this operation is produced by partial oxidation of char from the carbonization unit. The hydrotreater effluent is separated by distillation into recycled solvent and the product streams of gas, naphtha, and fuel oil (BO-117, KA-124, PH-025, RA-150).

Costeam

The Costeam Process is based on the reaction of coal with steam and carbon monoxide or synthesis gas to produce oil without the aid of a catalyst. The objective is to develop a liquefaction process for lignite.

Figure 33 is a flow diagram for the Costeam Process. Pulverized lignite is slurried with a process-derived recycled oil. The slurry feed, along with carbon monoxide or synthesis gas, is fed into the reactor operating at 4000 psi and 800° F. Water contained in the lignite provides the source of hydrogen for the liquefaction through the water-gas shift reaction in which carbon monoxide and water react to form hydrogen and carbon dioxide. The raw product is sent to a product separator where gas is separated from the liquid-solid mixture. This mixture is fed to a centrifuge or filter for solids removal. The final product is a low-sulfur, low-ash fuel oil (HA-260).

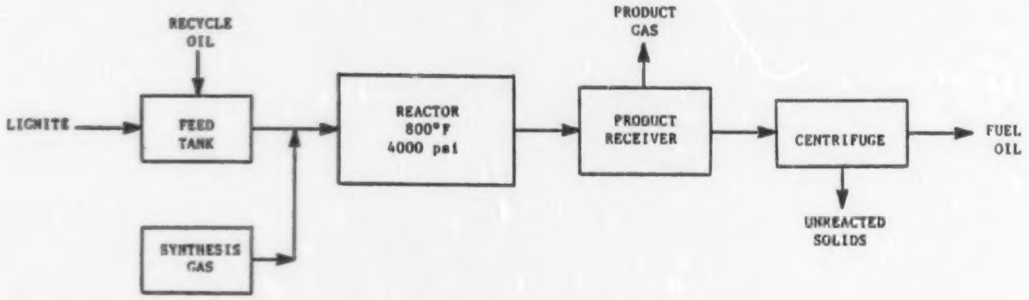

Figure 33. The Costeam Process.

Zinc Halide

Conoco is developing a coal liquefaction process based on catalytic hydrocracking with a zinc chloride catalyst. The process is designed to produce a 90 octane (lead-free) gasoline from coal. Early tests have been successful, but catalyst deactivation and loss are major problems.

Fischer-Tropsch

The Fischer-Tropsch process is the basis for a gasification-synthesis system. The process is a catalytic conversion which produces hydrocarbon liquids from coal-derived, intermediate-Btu synthesis gas. A Fischer-Tropsch liquefaction diagram is shown in Figure 34. Coal liquefaction in a Fischer-Tropsch plant is divided into (1) coal preparation, (2) coal gasification, (3) raw gas quenching and purification, (4) Fischer-Tropsch synthesis and products separation, (5) catalytic conversion of tail gas to produce additional methane, (6) clean-up section for the final removal of residual carbon dioxide and water from by-product SNG.

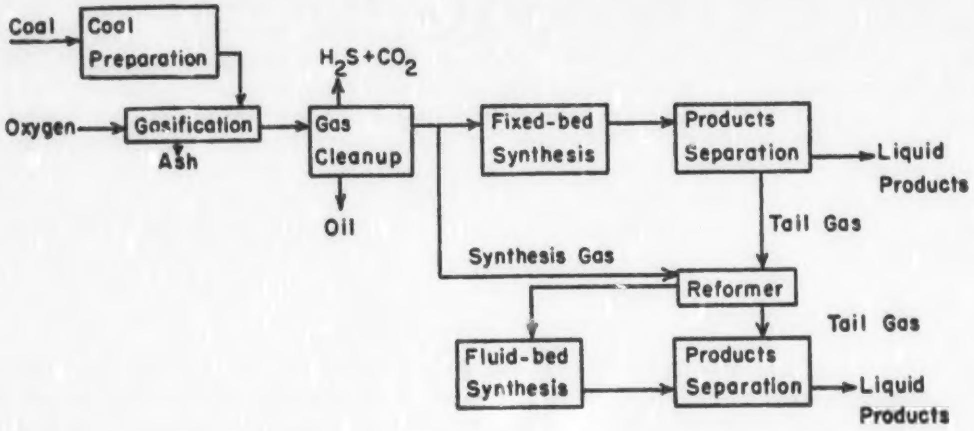
Coal
Coal Preparation
Oxygen
Gasification
Ash
H_2S+CO_2
Gas Cleanup
Oil
Fixed-bed Synthesis
Products Separation
Liquid Products
Tail Gas
Synthesis Gas
Reformer
Tail Gas
Fluid-bed Synthesis
Products Separation
Liquid Products

Figure 34. Fischer-Tropsch coal liquefaction process. (Source: UN-025)

The gasification-synthesis system is the only procedure currently being used to produce liquid fuels from coal on a commercial scale. A 10,000 ton per day commercial plant was built by the South African Coal, Oil and Gas Corporation (SASOL) in the Republic of South Africa.

In the SASOL process, the coal is gasified in a Lurgi reactor with steam and oxygen at approximately 1500° F and 380 psi. A gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and methane is produced. The gas is purified by a methanol wash for removal of sulfur compounds and carbon dioxide. The purified gas is then reformed with high purity oxygen and steam over a nickel catalyst to reduce the methane content. The reforming reactions are as follows:

$$CH_2 + H_2O \rightarrow CO + 2H_2$$

$$CH_4\ \tfrac{1}{2}O_2 \rightarrow CO + 2H_2$$

The carbon monoxide and the hydrogen from the reformer are then converted to liquid products by means of a Fischer-Tropsch synthesis. A simplified overall reaction may be expressed as follows:

$$8CO + 17\ H_2 \rightarrow C_8H_{18} + 8H_2O$$

Two types of reactors are used in the SASOL plant, a German "arge" unit and the American Kellogg Process. The arge process is a fixed bed process which primarily yields heavy fuel oils and diesel oils. The Kellogg process is a fluidized bed process which produces lower boiling materials such as LPG, gasoline and furnace oils. The Fischer-Tropsch synthesis takes place at 600° F and 350 psi over an iron catalyst. The reformer effluent gas is split and routed through both Fischer-Tropsch processes to produce a full range of liquid products (HO-207, RA-150).

Other Hydrogenation Research

In addition to the processes described, several research projects on liquefaction are currently underway. These projects are based upon hydrogenation processes. The Colorado School of Mines is determining the effects of process variables on the removal of sulfur from coal by treatment with hydrogen (GA-105). The University of Utah is studying intermediate coal hydrogenation processes in which tertralin® solvent is used in lignite hydrogenation/extraction. The University of North Dakota is conducting research on deriving premium fuels from lignite. Various projects on solvent refining of coal are underway at the University of Kentucky, the University of Michigan, and Auburn University.

Carbonization Processes

Carbonization refers to the liquefaction of coal by pyrolysis. Pyrolysis is the transformation of a compound into another substance or substances by heat alone. Coal is simply heated in reactors to produce volatile hydrocarbons or char residue. The hydrocarbons are recovered as process gas and liquid oils while char remains as a by-product of the process. The apparent simplicity of carbonization has always intrigued process developers. Unfortunately, several problems exist which prevent carbonization from being a matter of simply heating the coal. These problem areas are (1) residence time in the reactor, (2) caking coals, and (3) heat requirements.

COED

The Char Oil Energy Development Process (COED) is based on multi-stage fluidized-bed coal pyrolysis and converts coal into a synthetic crude oil, gas, and char. The gas can be used as a fuel or it can be processed for conversion to hydrogen. The char can also be burned as a fuel or gasified.

The COED process was developed by FMC Corporation to minimize agglomeration by heating coal in stages. It uses four fluidized-bed reactors or heating stages, each operating at a successively higher temperature. A flow diagram is shown in Figure 35.

In the first stage the coal is dried and heated to approximately 600° F with steam and combustion gases. This stage allows the softening point of the coal to be increased. The coal is subsequently fed to the second reactor where it is heated to about 850° F by recycle char and gas from the third stage. The overhead gases from the second stage contain the product gases and liquids. This overhead is scrubbed and routed to distillation for product recovery.

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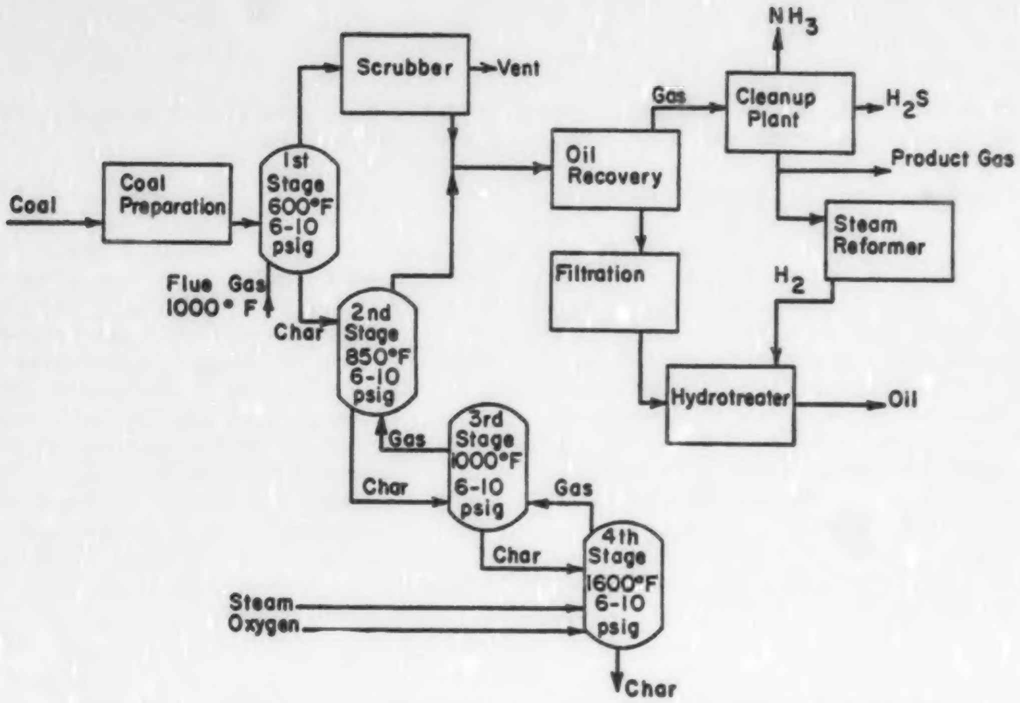


NH$_3$
Scrubber
Vent
Gas
Cleanup Plant
H$_2$S
Product Gas
Oil Recovery
Steam Reformer
Coal
Coal Preparation
1st Stage 600°F 6-10 psig
Flue Gas 1000° F
Char
2nd Stage 850°F 6-10 psig
Filtration
H$_2$
Hydrotreater
Oil
Gas
3rd Stage 1000°F 6-10 psig
Char
Gas
4th Stage 1600°F 6-10 psig
Char
Steam
Oxygen
Char

Figure 35. COED coal liquefaction process. (Source: UN-025)

Meanwhile, the char from the second stage is routed to the third reactor. The char is heated to approximately 1000° F by a combination of oxygen and hot gases from stage four. The char from stage three is routed to the fourth and final stage where it is heated to 1600° F with oxygen. The last stage produces hydrogen which is needed to hydrotreat the product tar. Synthesis crude oil produced from the COED process has a very high viscosity and must be hydrotreated rather severely to allow the oil to be pumped (BO-117, KA-124, RA-150, ZA-042).

U.S. Bureau of Mines Entrained Bed

The U.S. Bureau of Mines Entrained Bed Process avoids many of the problems associated with carbonization processes by pneumatically injecting coal into a reactor with air. The gas velocity is sufficiently high so that the coal moves up the reactor in plug flow. Short residence time provides high liquid yields. Agglomeration is avoided by contacting the coal with air during the carbonization step which partially oxidizes the surface of the coal particles. Unfortunately, the off-gases from this process are so diluted with nitrogen that they cannot be used for pipeline gas (RA-150).

Lurgi-Ruhrgas

The Lurgi-Ruhrgas Process uses a mechanical mixer to intimately contact coal and recycled hot char. The hot char supplies the heat for reaction. Agglomeration is no longer a problem since not only does the char act as a diluent, but the mixer also helps break up large particles. The liquid yield is fairly high since the residence time in the mixer is only a few seconds.

Product vapors leave overhead. Char from the mixer is superheated for recycling by reacting it with air in a transport reactor (RA-150).

Garrett Flash Pyrolysis

Garrett Research and Development Company is developing a flash pyrolysis coal liquefaction process that uses an entrained bed reactor. The process is based on partial gasification in which the direct yield of methane and other hydrocarbons is obtained by rapid coal pyrolysis. Pulverized coal is conveyed by recycled gas to the entrained bed reactor which is heated by recycled char from a char heater and maintained at 1100° F. Reactor effluent passes through cyclones to separate the char from the gas. Some of the char is cooled as a by-product. The remaining char goes to a char heater where some is burned to reheat the char to approximately 1400° F for recycling in the reactor. The gas stream is cooled and the tar (liquids) separated. The gas is separated into three streams. One stream is used to entrain the coal fed to the reactor. Another stream is routed to the product after acid gas is removed. The remaining gas is used in the production of hydrogen for hydrotreating the process tar. At the hydrotreater the tar is upgraded to obtain a synthetic crude oil (RA-150).

TOSCOAL

The Oil Shale Company (TOSCO) has investigated the application of its oil shale retorting technology to the low-temperature carbonization of coal. This application to processing coal is designated the TOSCOAL process. The basic feature is that the required heat is provided by hot ceramic balls. The process is shown in Figure 36. Crushed coal is preheated with hot flue gas and

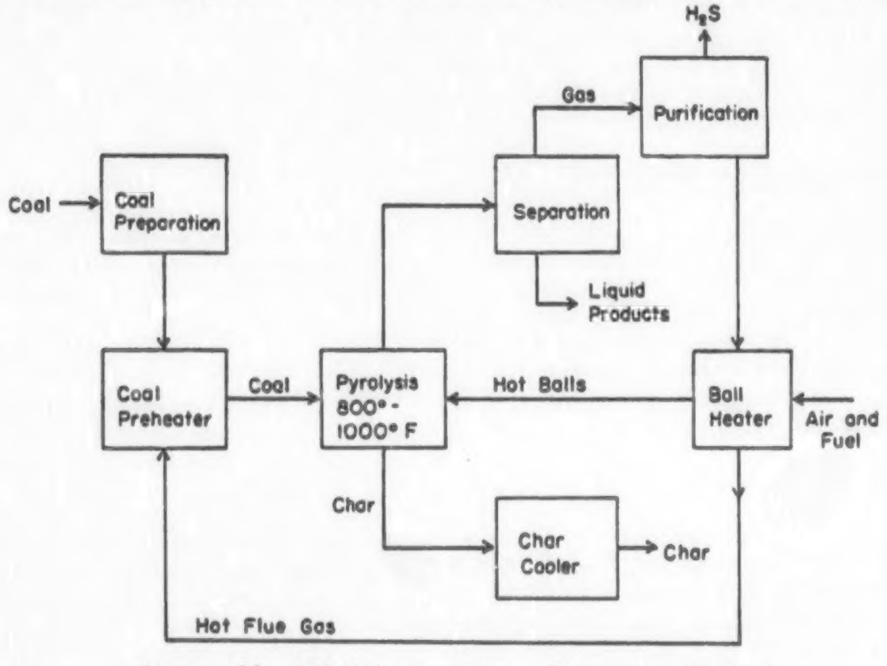


Figure 36. TOSCOAL process. (Source: UN-025)

is then transferred to a rotating pyrolysis drum where it is heated to the carbonization temperature by contact with hot ceramic balls. A trommel screen is used to separate the ceramic balls from the char product. The balls are conveyed to a heater and recycled. With about 50% of the weight of the raw coal feed and about 80% of the raw coal heating value, the char can be used as a fuel. Pyrolysis vapors are condensed and liquid products are fraction ated into gas oil, naphtha and residuum. Uncondensed gas is used as a fuel in the ball heater (BO-117, CA-215, KA-124).

OIL SHALE TECHNOLOGY

Oil Shale Extraction

Oil shale mining procedures consist of the same techniques used in coal mining. The main differences between the two industries result from the massive solids handling problems associated with oil shale extraction. Approximately 73,700 tons per day of raw oil shale containing 30 gallons of oil per ton of shale must be extracted to support a 50,000 barrels-per-day refinery. Significant differences in the mining techniques also arise because oil shale deposits are often much thicker than coal seams and oil shale is considerably harder than coal.

Oil shale production methods include underground (room and pillar) mining, surface mining, and in-situ oil shale processing. In-situ methods will be discussed in the processing section. Depending upon the physical characteristics at the particular oil shale site, oil shale may be mined by either surface or underground methods. Most actual experience involves underground mining which is more universally applicable to the various oil shale deposits than surface mining.

Underground Mining

Room and pillar mining is the most efficient method for mining oil shale underground. The oil shale deposit is entered via a tunnel dug into the side of a valley where an outcrop appears. Pillars of ore are left in place at appropriate intervals within the mine to provide roof support. Due to the large amount of shale that must be extracted in order to produce a significant amount of oil, room and pillar shale mining is more like an underground quarrying operation. A typical raw shale bed is 40 feet thick with a density of 90 pound/foot^3 (US-093). Underground extraction is estimated to be capable of removing approximately 65% of the shale from a typical mine (HI-083).

Extraction is accomplished by drilling and blasting the shale. The broken shale is loaded onto diesel trucks and transported to a portable crusher. Crusher discharge is conveyed to underground storage bins. From the storage bin, shale is transported to secondary crushers on the surface.

Surface Mining

Surface mining consists of removal of the overburden followed by mining of the underlying oil shale in a quarry-like operation. Factors affecting the suitability of surface mining are the ratio of the overburden to the shale to be mined and the availability of a disposal area for the overburden. In comparison with underground mining, surface mining is capable of extraction at a lower cost, requires less manpower (HI-083), and is inherently safer. Unfortunately, potential sites for surface mining are limited and there is a high land impact since all of the spent shale and solid waste must be handled on the surface.

Overburden at potential surface mining sites ranges from 100 feet to 800 feet in depth, averaging approximately 450 feet. Due to the required mine depth, several bench levels must be provided to develop sufficient working faces to meet production rates. An average mine slope of 45° with a working slope of 35° is typical (US-093). Overburden and shale are extracted by drilling and blasting. Blasted raw shale is hauled by trucks to primary crushers in the pit. Shale from the crusher is removed from the mine by conveyor to secondary crushing and screening facilities. The secondary crushing and screening facilities may be located at the upgrading plant site. Major processing steps associated with a surface mining operation are shown in Figure 37.

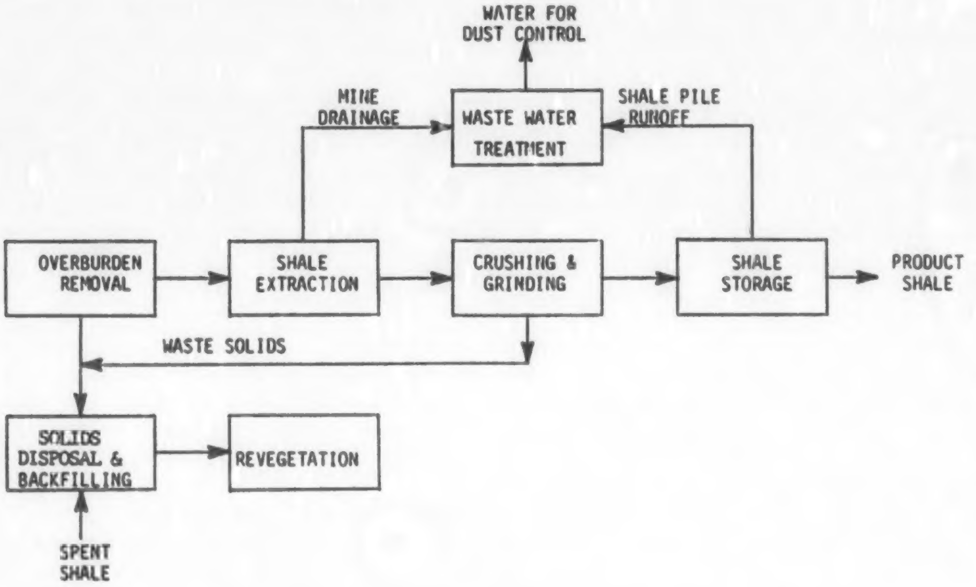

WATER FOR DUST CONTROL
MINE DRAINAGE
WASTE WATER TREATMENT
SHALE PILE RUNOFF
OVERBURDEN REMOVAL
SHALE EXTRACTION
CRUSHING & GRINDING
SHALE STORAGE
PRODUCT SHALE
WASTE SOLIDS
SOLIDS DISPOSAL & BACKFILLING
REVEGETATION
SPENT SHALE

Figure 37. Steps involved in oil shale surface mining

Sizing Operations

Sizing operations which may be performed on raw shale include primary, secondary, and tertiary crushing, screening, and briquetting. The amount of sizing required depends upon the specific retorting process being used. Retorts that rely on solids-to-solids heat transfer require a smaller size feed than retorts relying on gas-to-solids heat transfer. The TOSCO II (The Oil Shale Company) retort requires shale ground to less than 0.5 inches while

Union and Gas Combustion Company retorts can accommodate ore up to 3.5 inches. Operations which may potentially be employed in a shale sizing facility are shown in Figure 38.

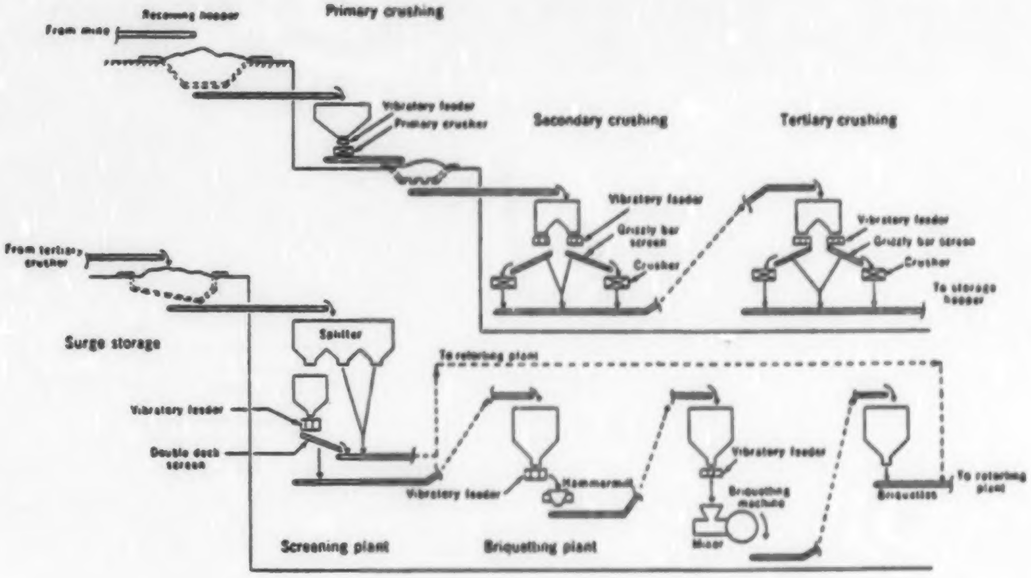

Receiving hopper
From mine
Primary crushing
Vibratory feeder
Primary crusher
Secondary crushing
Tertiary crushing
Vibratory feeder
Grizzly bar screen
Crusher
Vibratory feeder
Grizzly bar screen
Crusher
To storage hopper
From tertiary crusher
Surge storage
Splitter
To retorting plant
Vibratory feeder
Double deck screen
Vibratory feeder
Hammermill
Vibratory feeder
Briquetting machine
Mixer
Briquettes
To retorting plant
Screening plant
Briquetting plant

Figure 38. Shale sizing operations. (Source: US-093)

Primary crushers are normally located close to the blasting operation to cut down on the transportation of large blocks of shale. Only after the shale has been initially crushed does it leave the immediate mining area. The shale is conveyed to secondary and tertiary crushers outside the mine or pit. The remaining sizing operations may be performed at the mine site or retorting site. As such they may be considered as part of the mining operation or as a preparation step in the retorting process.

After secondary and tertiary crushing, the shale is conveyed to shale storage hoppers and then may be fed directly to the retort. A screening operation may be used on all or a portion of the shale stream to separate the acceptable shale from fines. Fines from the screening process are compacted with a hammer mill and formed into briquettes prior to routing to the retort.

Oil Shale Processing

Oil shale processing to obtain hydrocarbon products consists of two stages. The hydrocarbon products, both liquid and gaseous, are derived from kerogen, a solid organic constituent of oil shale which may be converted to conventional petroleum products. In the first stage, oil shale is heated by a pyrolysis reaction to decompose the kerogen into gases and a liquid hydrocarbon (shale oil). This heating step or retorting process is a basic requirement of all shale oil processes. The various oil shale processes are characterized by the manner in which the shale is retorted and the mechanism by which the necessary heat is supplied. The second processing stage is the upgrading of the shale oil for transportation and use. The upgrading is accomplished with conventional petroleum refining techniques and requires essentially the same facilities for all shale oil processes. Figure 39 is a flow diagram for a typical shale oil process.

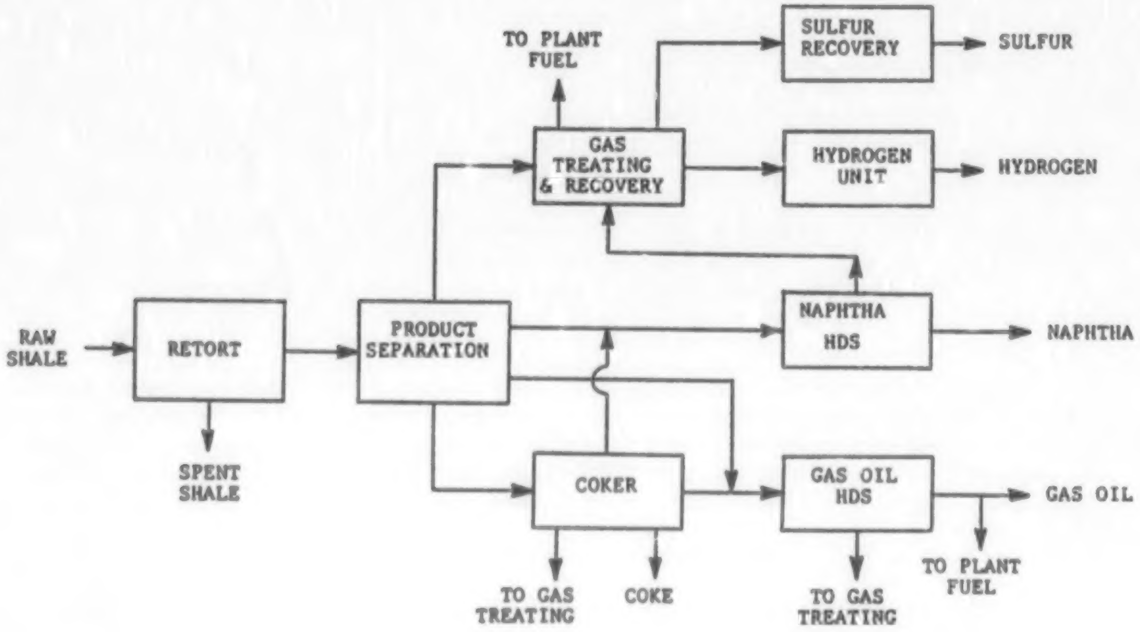

TO PLANT FUEL
SULFUR RECOVERY
SULFUR
GAS TREATING & RECOVERY
HYDROGEN UNIT
HYDROGEN
RAW SHALE
RETORT
PRODUCT SEPARATION
NAPHTHA HDS
NAPHTHA
SPENT SHALE
COKER
GAS OIL HDS
GAS OIL
TO GAS TREATING
COKE
TO GAS TREATING
TO PLANT FUEL

Figure 39. Typical shale oil process.

Oil Shale Retorting

The retorting step is the heart of the shale oil process. Most of the differences that exist between processes are a result of the retorting procedure. The first distinction of the processes depends on whether the retorting is accomplished on the surface or underground (in-situ). Surface processes are more advanced and are nearing commercialization while in-situ processes are still in the developmental stage. Within these two broad categories, shale oil processes can be further distinguished by retorting procedures. Basic retorting methods are shown in Figure 40.

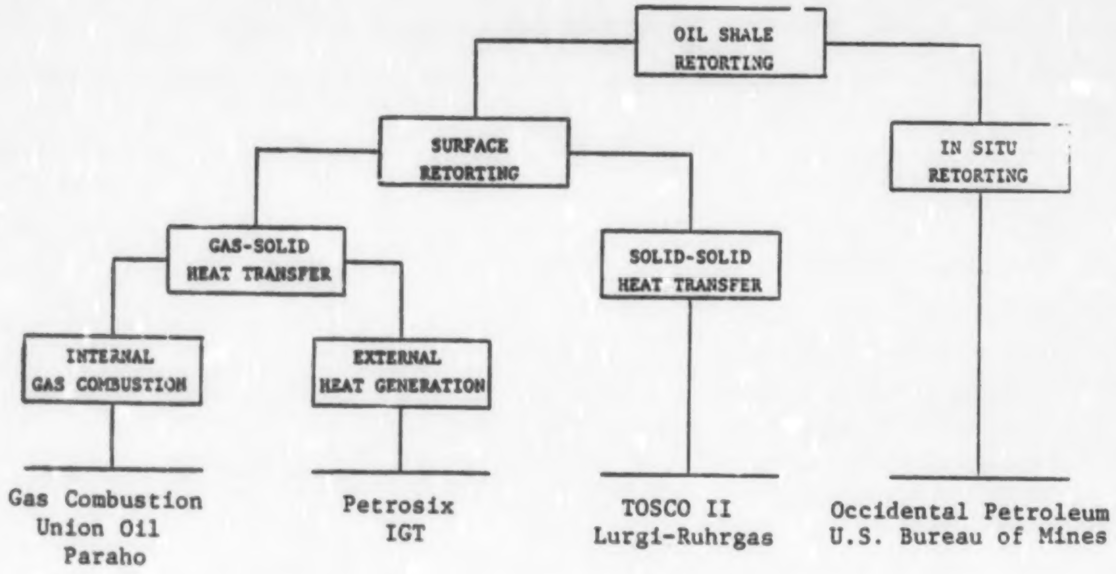

OIL SHALE RETORTING
SURFACE RETORTING
IN SITU RETORTING
GAS-SOLID HEAT TRANSFER
SOLID-SOLID HEAT TRANSFER
INTERNAL GAS COMBUSTION
EXTERNAL HEAT GENERATION
Gas Combustion
Union Oil
Paraho
Petrosix
IGT
TOSCO II
Lurgi-Ruhrgas
Occidental Petroleum
U.S. Bureau of Mines

Figure 40. Classification of retorting processes.

Surface retorting processes are distinguished by the retorting vessel and in particular by the method in which the necessary pyrolysis heat is supplied. Current processes involve either solid-solid or gas-solid heat transfer (HE-100).

Processes that use solids-to-solids heating rely on heated solids such as ceramic balls, sand, or spent shale particles to supply the retorting heat. These processes heat the particles in an external heater and then mix them with the raw shale in the retort. After retorting, the heated solids must be separated for recycling from the spent shale.

Processes which involve gas-to-solids heating use either internal gas combustion or external heat generation (HE-100, RA-150). Processes using internal gas combustion inject air directly into the retort. The heat liberated by the resulting combustion of fuel gas and carbon residue provides the retorting temperature. Processes using external heat generation rely on external heaters to provide a high-temperature recycled gas which may be routed into the retort. Some processes using internal gas combustion include plans or capabilities to use external heating of recycled gas to provide the retorting heat (PF-003, LI-094).

Operating conditions of the different retorts vary and this effects the product streams. A comparison of the effluent oil from three retorts is show in TABLE 7.

TABLE 7. CHARACTERISTICS OF CRUDE SHALE OILS

	Retorting Process		
	Gas Combustion	Union[1]	TOSCO[2]
Gravity, °API	19.7	20.7	28.0
Sulfur, weight-percent (wt-pct)	0.74	0.77	0.80
Nitrogen, weight-percent	2.18	2.01	1.70
Pour point, °F	80	90	75
Viscosity, SUS @100° F	256	223	120

[1] Typical of product from original Union process.

[2] Unpublished information submitted by Colony Development Company indicates TOSCO crude shale oil may have gravity as low as 21° API and sulfur content of 0.75 wt-pct.

Gases produced in shale oil processes vary significantly, depending on retort type. Gases from internal combustion retorts are diluted with combustion products and the inert components of the air. As a result the gas has a low heating value, 100 Btu/scf, and cannot be economically transported any significant distance. Gas from retorts which utilize indirect heating is composed only of undiluted components from the kerogen and has a substantially higher heating value, 800 Btu/scf. A comparison of gases from internal combustion and indirect heat retorts is shown in TABLE 8.

Physical properties and quality of the spent shale also change with the retort. The amount of carbonaceous material remaining on the shale is inversely proportional to the retort temperature. The low temperature shale from a TOSCO retort contains 5%-6% carbonaceous material, intermediate temperature gas combustion 3%, and high temperature shale from the Union retort contains essentially none.

In-situ processing proposes to retort the shale in place, and thus avoid the solids handling problems associated with more conventional mining techniques. In-situ processing involves fracturing the shale, injection of retorting fluids, retorting of the shale in-place, and recovery of the product. Potential methods for fracturing the shale include hydraulic, electrical, chemical explosive, and nuclear methods.

In-situ oil shale processing is still in the development stage. The two potential in-situ processes are the U.S. Bureau of Mines horizontal sweep method and the Occidental Company mine and collapse method.

TABLE 8. CHARACTERISTICS AND YIELDS OF UNTREATED RETORT GASES
(Source: US-093)

	Type of Retorting Process			
	Internal Combustion		Indirectly Heated	
Composition, vol. pct	2/	2/	As Produced	When Desulfurized
Nitrogen 1/	60.1	62.1	--	--
Carbon monoxide	4.7	2.3	4.0	4.2
Carbon dioxide	29.7	24.5	23.6	24.8
Hydrogen Sulfide	0.1	0.1	4.7	(0.02)
Hydrogen	2.2	5.7	24.8	26.0
Hydrocarbons	3.2	5.3	42.9	45.0
Gross Heating Value, Btu/scf	83	100	775	815
Molecular Weight	32	30	25	24.7
Yield, scf/bbl oil 3/	20,560	10,900	923	880

1/ Includes oxygen of less than 1.0 volume percent.
2/ First analysis reflects relatively high-temperature retorting in comparison with second, promoting higher yield of carbon oxides from shale carbonate and relatively high yield of total gas.
3/ Oil from the retort

In-situ oil shale processing is still in the development stage. The two potential in-situ processes are the U.S. Bureau of Mines horizontal sweep method and the Occidental Company mine and collapse method.

Current oil shale processes are described in the following sections.

TOSCO II

The TOSCO II process features a rotary retort which uses ceramic balls to supply the retorting heat by a solids-to-solids heat transfer. A flow diagram of the TOSCO II process is shown in Figure 41.

Raw oil shale, crushed to less that ½-inch, is fed into a fluidized bed where it is heated to approximately 500° F by hot flue gas from the ceramic ball heater. The preheater effluent is routed to settling chambers and cyclones in order to separate the preheated shale from the flue gas. Following shale separation, the cooler flue gas, which has been incinerated within the preheat system to reduce trace hydrocarbons, is passed through a high energy venturi to remove shale dust before being vented to the atmosphere at a temperature of 125-130° F.

Preheated raw shale from the cyclone separators is fed to the horizontal, rotating retort and mixed with hot ceramic balls (½-inch diameter). The balls are heated to about 1200° F in a furnace fired by product fuel gas. Pyrolysis occurs because a temperature of 900° F is maintained by the transfer of heat from the balls to the shale. An internal pressure of 5 psig is maintained to prevent the entrance of air. The rotating retort is essentially a ball mill; as the kerogen decomposes, the oil shale loses strength and is pulverized by

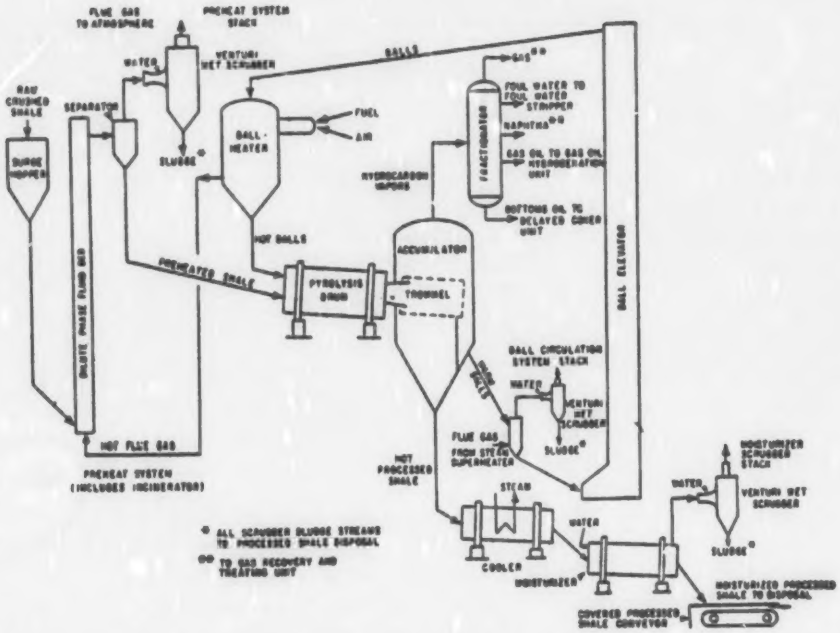

FLUE GAS TO ATMOSPHERE
PREHEAT SYSTEM STACK
VENTURI WET SCRUBBER
WATER
BALLS
RAW CRUSHED SHALE
SEPARATOR
SURGE HOPPER
SLUDGE*
BALL-HEATER
FUEL
AIR
GAS**
FOUL WATER TO FOUL WATER STRIPPER
NAPHTHA**
FRACTIONATOR
GAS OIL TO GAS OIL HYDROGENERATION UNIT
HYDROCARBON VAPORS
BOTTOMS OIL TO DELAYED COKER UNIT
DILUTE PHASE FLUID BED
HOT BALLS
ACCUMULATOR
PREHEATED SHALE
PYROLYSIS DRUM
TROMMEL
BALL ELEVATOR
BALL CIRCULATION SYSTEM STACK
WATER
VENTURI WET SCRUBBER
FLUE GAS FROM STEAM SUPERHEATER
SLUDGE*
HOT FLUE GAS
PREHEAT SYSTEM (INCLUDES INCINERATOR)
HOT PROCESSED SHALE
MOISTURIZER SCRUBBER STACK
STEAM
WATER
VENTURI WET SCRUBBER
WATER
* ALL SCRUBBER SLUDGE STREAMS TO PROCESSED SHALE DISPOSAL
** TO GAS RECOVERY AND TREATING UNIT
COOLER
SLUDGE*
MOISTURIZER*
MOISTURIZED PROCESSED SHALE TO DISPOSAL
COVERED PROCESSED SHALE CONVEYOR

Figure 41. TOSCO II retorting procedure.

the ceramic balls. Approximately 5% to 6% carbonaceous material remains on the shale. The fuel gas produced is not diluted by combustion products and consequently has a higher heating value. Approximately 900 scf of fuel gas with a heating value of 800 Btu is produced per barrel (bbl) of oil from the retort.

During pyrolysis, the shale oil, steam, and gases are emitted as vapors and fed to a fractionator for product recovery. The retort products are normally separated into fuel gas, sour water, naphtha, gas oil, and bottom oil streams. A series of parallel operations follow the fractionation as product streams are upgraded and by-products are recovered.

Retort products are routed to an accumulator where the solids are passed over a trommel screen to separate the balls from the spent shale. The ceramic balls are recycled to the vertical ball heater by means of bucket elevator. In the ball heater, fuel gas is combusted to heat the balls to 1200° F.

The spent shale is cooled in a rotating drum steam generator and moisturized to approximately 14% moisture content in a rotating drum moisturizer. Steam and shale dust produced during the moisturizing step are routed through a venturi scrubber to remove the dust before they are discharged to the atmosphere. Following moisturizing, the spent shale is conveyed to a disposal site. Dust collected from the various venturi scrubbers is also routed offsite with the processed shale.

Paraho

The Paraho retort has the capability of using either direct gas combustion or externally heated recycled gas to achieve the retorting temperature (PF-003). Coarsely ground shale oil is introduced at the top and flows by gravity down through the vertical retort. Combustion air and recycled gas (or heated gas) are introduced at several points in the retort, flowing upward countercurrent to the shale. Combustion of these gases with the residual carbon on the shale liberates the heat necessary for retorting. If heated recycled gas is utilized, then steam will provide the heat necessary for retorting. Spent shale is removed from the bottom of the retort. A discharge grate improves the downward flow of shale over the unit cross-section and provides for a careful distribution of incoming gases (HE-100). Shale oil vapors exit overhead, passing through an electrostatic precipitator and then to a gas recovery unit. A portion of the noncondensible gas is returned to the retort as combustion gas with the remainder routed to a waster heat boiler. The Paraho retort step is shown in figure 42.

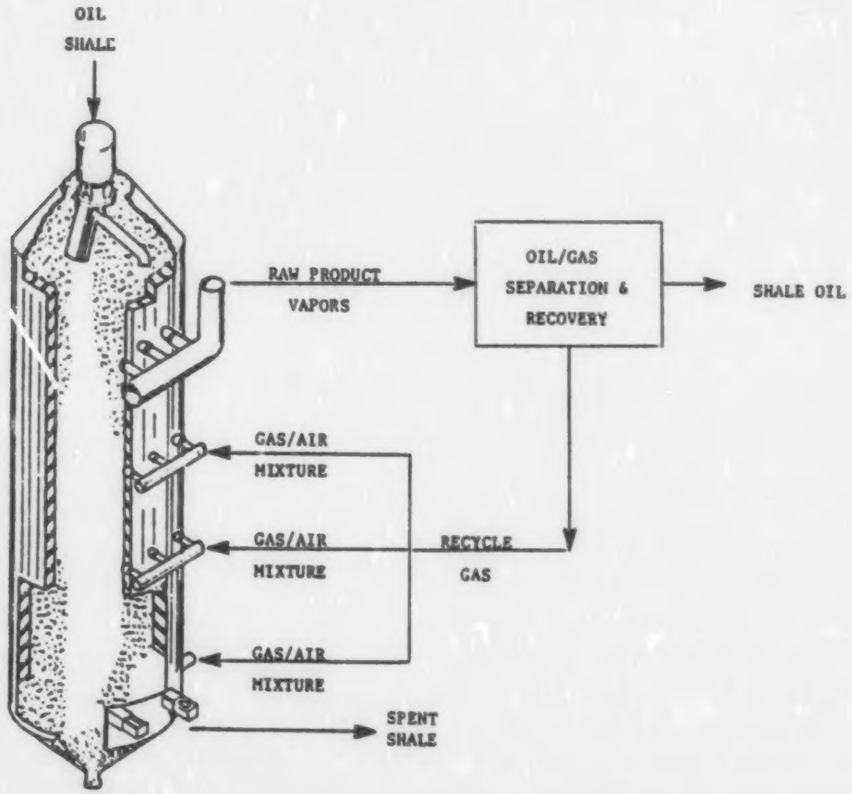


Figure 42. The Paraho retort process.

Lurgi-Ruhrgas

The Lurgi-Ruhrgas Process shown in Figure 43 uses small solids such as sand, coke particles, or spent shale to heat incoming oil shale. The solids are preheated and mixed with raw shale in a sealed screw-conveyor that acts as the retort (HE-100). The effluent from the retort is discharged into a bin for separation. Solids are removed from the lower part of the bin for recycling. Product vapors containing dust and condensation are removed overhead (GA-107, RA-150).

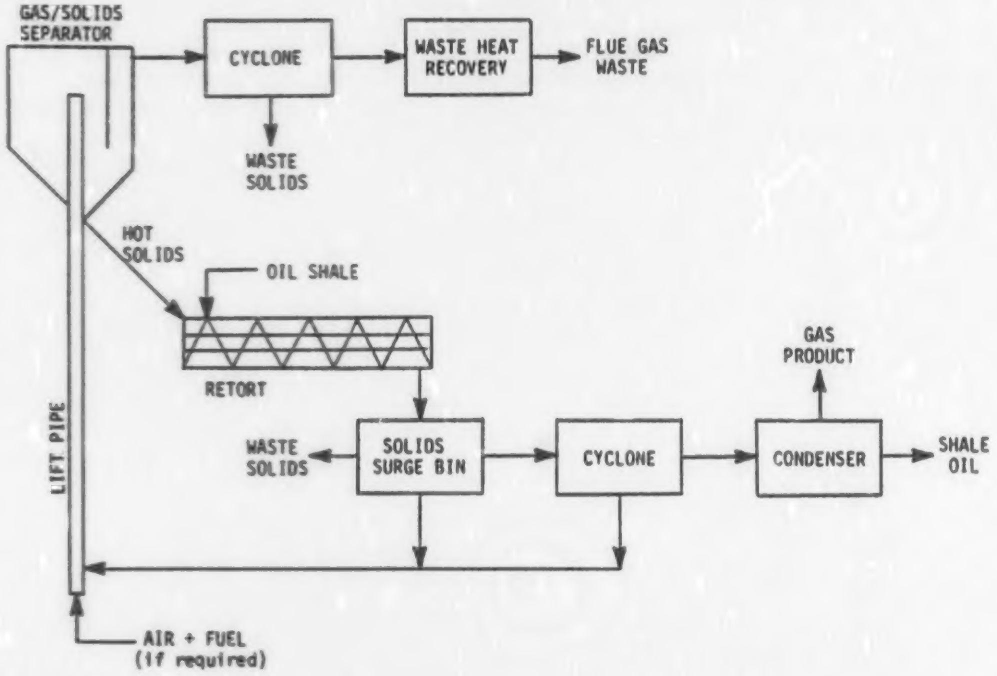

GAS/SOLIDS SEPARATOR
CYCLONE
WASTE HEAT RECOVERY
FLUE GAS WASTE
WASTE SOLIDS
HOT SOLIDS
OIL SHALE
RETORT
GAS PRODUCT
LIFT PIPE
WASTE SOLIDS
SOLIDS SURGE BIN
CYCLONE
CONDENSER
SHALE OIL
AIR + FUEL (if required)

Figure 43. The Lurgi Ruhrgas oil shale retorting process.

U.S. Bureau of Mines Gas Combustion

The U.S. Bureau of Mines Gas Combustion retort is a vertical, refractory-lined vessel. Coarsely ground oil shale is introduced at the top and flows by gravity downward through the retort. Although no physical barriers are present in the vessel, the retort may be considered to consist of four sections for shale preheating, retorting, combustion, and cooling.

Combustion air and recycled gas are injected into the combustion zone, approximately 1/3 of the way up the retort. Combustion of the gases with residual carbon on the spent shale liberates the heat necessary for retorting. Combustion temperature is approximately 1200-1400° F. Retorting occurs above the combustion zone. Product vapors from the retorting section are cooled by the incoming shale and withdrawn. Heat exchange between product vapors and raw shale preheats the shale prior to retorting. Following combustion, spent shale in cooled and removed from the bottom of the retort. Recycled gas entering at the bottom of the retort is used to cool the spent shale (KA-133, RA-150). The Gas Combustion retorting process is shown in Figure 44.

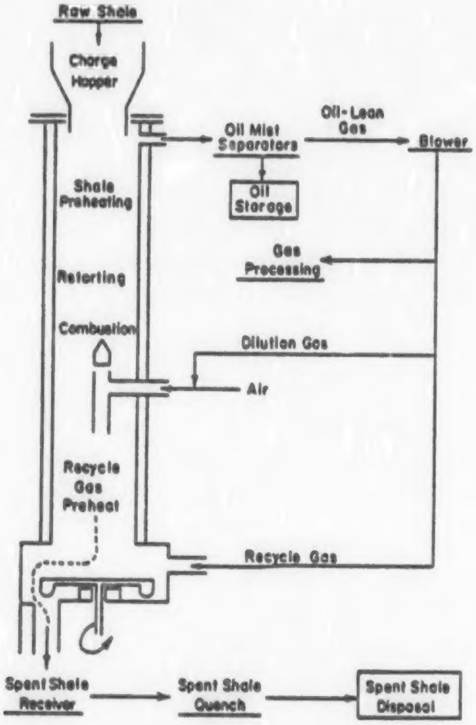

Raw Shale
Charge Hopper
Oil Mist Separators
Oil-Lean Gas
Blower
Oil Storage
Shale Preheating
Gas Processing
Retorting
Combustion
Dilution Gas
Air
Recycle Gas Preheat
Recycle Gas
Spent Shale Receiver
Spent Shale Quench
Spent Shale Disposal

Figure 44. U.S. Bureau of Mines Gas Combustion retorting process.

Union Oil

The Union Oil Company Process uses internal gas combustion to provide the retorting heat. The retort is a vertical refractory-lined vessel in the shape of an inverted cone. The top of the retort is open to the atmosphere. Air enters from the top while shale is introduced at the bottom by a rock pump. Combustion of the organic matter remaining on the shale heats the shale by direct gas-to-solids exchange. Maximum shale temperature in this process is approximately 1800° F. Spent shale solids overflow the vessel at the top. The product oil is cooled by the incoming shale and removed through an outlet at the bottom of the retort. The advantage of this design is that oil products cannot drip down to hotter parts of the retort and leave heavy residues that must be removed (UN-025). The Union Oil Company retort is shown in Figure 45. Union Oil Company is also working on an alternative configuration with external heat generation (HE-100,LI-094).

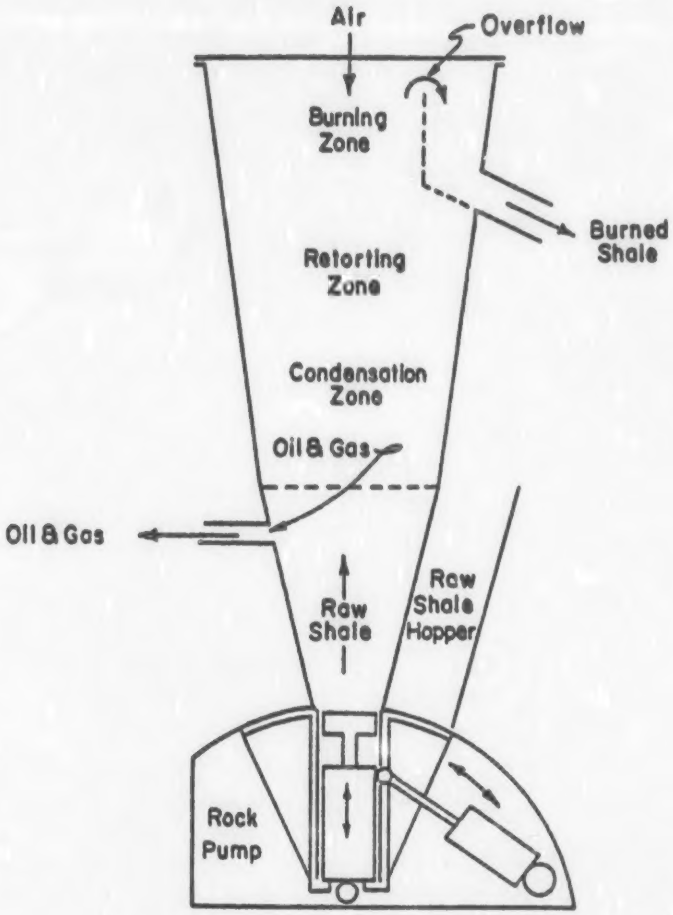

Air
Overflow
Burning Zone
Burned Shale
Retorting Zone
Condensation Zone
Oil & Gas
Oil & Gas
Raw Shale
Raw Shale Hopper
Rock Pump

Figure 45. Union Oil Company retort.

Petrosix

The Petrosix Process is similar to the gas combustion process used by the U.S. Bureau of Mines except that the Petrosix Process injects externally-heated recycled gas into the vertical kiln retort rather than combustion air. Crushed shale enters at the top and moves down through zones of preheating, retorting, and cooling. Recycled gas, heated in a separate furnance, is injected into the retorting area of the vessel (FR-115). Since heat generation is external, a combustion zone is not present in this retort. Retorting products moving upward in the vessel are cooled by incoming raw shale prior to leaving the retort. An unheated recycled gas stream is injected at the bottom of the retort to recover sensible heat and cool the spent shale. Spent shale is removed at the bottom of the vessel and slurried to a disposal area. A diagram of the Petrosix Process is shown in Figure 46.

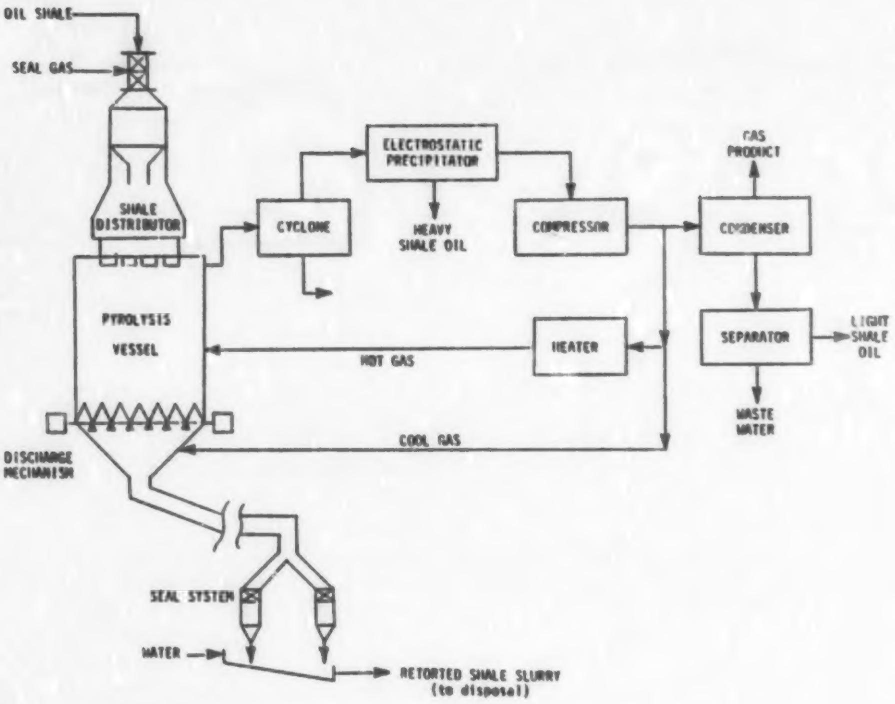

OIL SHALE
SEAL GAS
SHALE DISTRIBUTOR
CYCLONE
ELECTROSTATIC PRECIPITATOR
HEAVY SHALE OIL
COMPRESSOR
GAS PRODUCT
CONDENSER
PYROLYSIS VESSEL
HOT GAS
HEATER
SEPARATOR
LIGHT SHALE OIL
WASTE WATER
COOL GAS
DISCHARGE MECHANISM
SEAL SYSTEM
WATER
RETORTED SHALE SLURRY (to disposal)

Figure 46. Petrosix Process flow diagram.

IGT Retort

The key feature of the Institute of Gas Technology (IGT) retort is the moderate-pressure hydrogen atmosphere. The vertical retort is internally divided into three zones. Shale passing downward is prehydrogenated and preheated in the top zone, hydroretorted in the middle zone, and cooled in the bottom zone. One hydrogen stream picks up some heat from the spent shale and after additional heating, is used to preheat incoming raw shale. A second hydrogen stream is internally heated and passes through the middle retorting zone to hydroretort the kerogen. Varying the reaction temperature varies the ratio of liquid to gaseous products (GA-107, HE-100). Figure 47 is a flow diagram of the IGT Process.

Superior

The Superior Oil Company Process for shale oil recovery differs from other oil shale ventures because the emphasis is not on the retort design. The key feature of this process is the simultaneous recovery of associated minerals. The Superior Oil Company Process depends on oil shale that contains the minerals nahcolite (naturally occurring sodium bicarbonate) and dawsonite (a sodium aluminum carbonate). The oil shale can be processed into low sulfur fuel oil, natural sodium bicarbonate, soda ash, and aluminum compounds (WE-163, WE-164, WE-166). Since four products result from the Superior Process, it is an integrated process. Figure 48 is the flow diagram for the Superior Process.

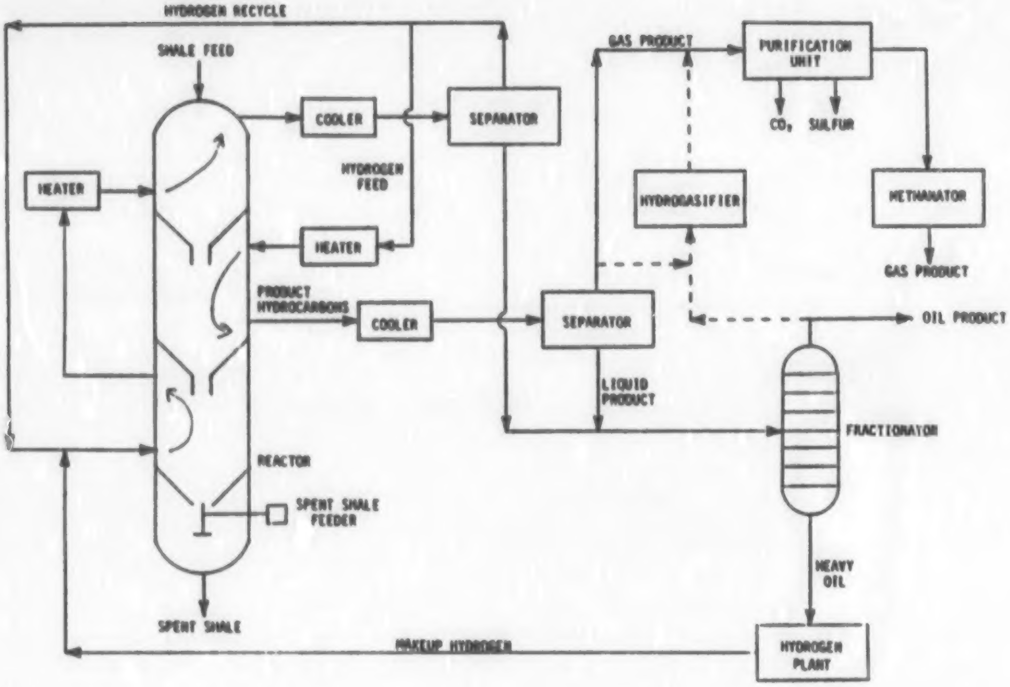

HYDROGEN RECYCLE
SHALE FEED
COOLER
SEPARATOR
GAS PRODUCT
PURIFICATION UNIT
CO$_2$
SULFUR
HEATER
HYDROGEN FEED
HYDROGASIFIER
METHANATOR
HEATER
GAS PRODUCT
PRODUCT HYDROCARBONS
COOLER
SEPARATOR
OIL PRODUCT
LIQUID PRODUCT
FRACTIONATOR
REACTOR
SPENT SHALE FEEDER
HEAVY OIL
SPENT SHALE
MAKEUP HYDROGEN
HYDROGEN PLANT

Figure 47. Flow diagram of Institute of Gas Technology oil shale process.

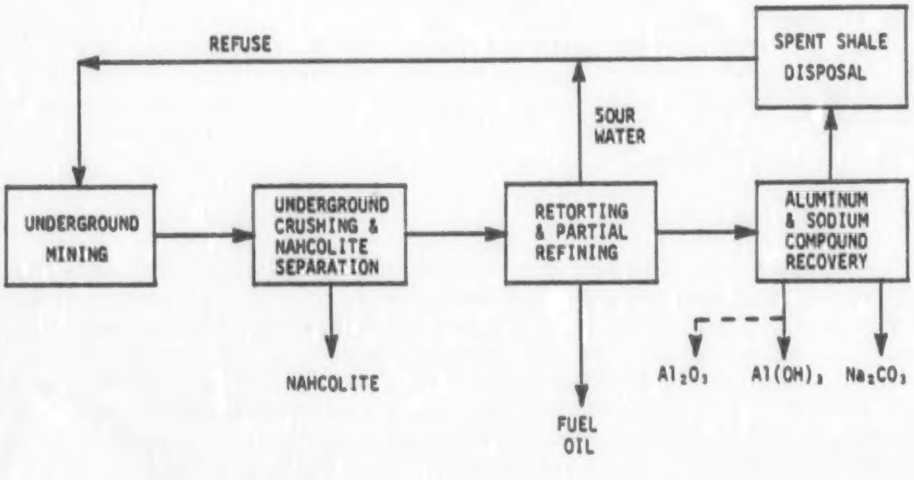

REFUSE
SPENT SHALE DISPOSAL
SOUR WATER
UNDERGROUND MINING
UNDERGROUND CRUSHING & NAHCOLITE SEPARATION
RETORTING & PARTIAL REFINING
ALUMINUM & SODIUM COMPOUND RECOVERY
NAHCOLITE
FUEL OIL
Al$_2$O$_3$
Al(OH)$_3$
Na$_2$CO$_3$

Figure 48. Flow diagram of Superior oil shale process.

After mining, raw nahcolite is separated from the oil shale by a mechanical crushing and screening process. The oil shale is very difficult to fracture, but the nahcolite is very brittle and fractures easily (WE-163).

The closed system retort is proprietary, but here the oil shale containing dawsonite is pyrolized. The retort is called a circular grate retort. The circular retort which is easily sealed passes the shale through several processing zones. In each zone, the shale is treated differently in preparation for the extraction of alumina and soda ash. The four zones in the retort are the loading and unloading, retorting, cooling, and residual carbon recovery zones. The hydrocarbon product is withdrawn as a vapor and fed to a fractionator for upgrading. The initial processing of the dawsonite begins in the retort where the sodium aluminum carbonate decomposes to sodium carbonate and a soluble aluminum compound. These two compounds remain in the spent shale when it is discharged from the retort and fed to a light caustic leach (WE-163, WE-166).

As the spent shale is removed by filtration, the soluble aluminum compound and the sodium bicarbonate dissolve in the caustic solution which is beneficiated by countercurrent decantation. Next, aluminum trihydrate is separated from the liquor by carbonation and filtration. The carbonate-rich liquor is evaporated for soda ash recovery, and the condensed water is recycled.

Although the shale increases in volume during processing, it can be returned to the mine for disposal because about 50 percent of the originally mined material is removed during the processing.

U.S. Bureau of Mines In-Situ Process

In the U.S. Bureau of Mines In-Situ Process, parallel rows of wells (injection and production) are drilled along two opposing sides of an oil shale deposit, and the shale is fractured along horizontal planes (BU-123, UN-025). Once the shale is fractured, a retorting fluid (hot gas or steam) is introduced through injection wells. The gas is injected at a rate sufficient to maintain a satisfactory temperature and/or flame front within the shale formation. The shale is brought to the retorting temperature (900° F), and the kerogen is decomposed. The hot gases create a pressure differential within the formation forcing the shale oil vapors into the producing wells. The row of production wells brings to the surface a gas with entrained liquid. Liquid which may gather at the bottom of the shale bed is pumped out. A schematic of this process is shown in Figure 49. The process operates like a horizontal retort in which retorted shale oil is pushed toward the product point by an advancing combustion zone.

Conventional processing is used after the liquid is pumped from the shale bed. Liquid is also recovered from the gas stream. The gas stream, which has a heating value of about 30 Btu/scf is primarily recycled into the shale formation. The gas which cannot be injected is treated for acid gas removal and flared.

Occidental In-Situ Process

The Occidental Petroleum Company In-Situ Process, developed by its subsidiary, Garrett Research and Development Company, involves a limited amount

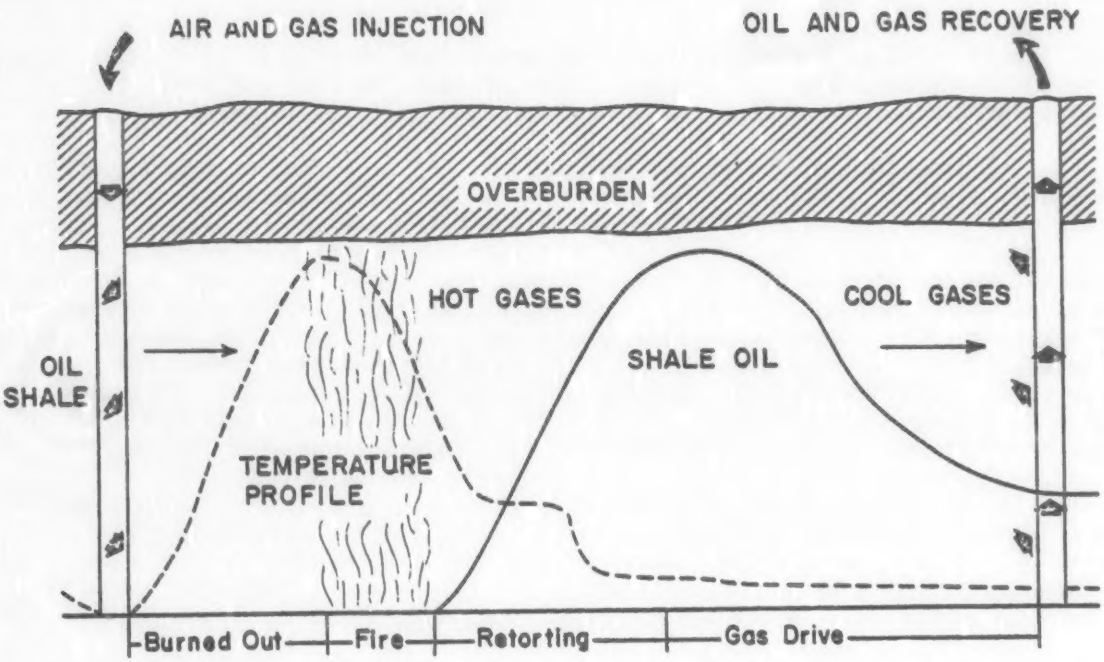


Figure 49. Schematic representation of an in-situ retorting operation. (Source: UN-025)

of conventional mining, blasting of the remaining shale to form the retort, and retorting in-place using air and underground combustion (HE-100).

Conventional mining techniques are used to excavate rock just below the target zone, and collector pipes are subsequently installed on the floor of the mined area. Explosives are then used to fracture the overlying oil shale to form a large underground retorting room. Combustion is initiated at the top using an outside fuel source. The combustion heat retorts the top shale to yield shale oil, some gas, and residual carbon. Off-gas is recirculated to control oxygen concentration and burning rate. Shale oil drains to the bottom of the retort where it is collected and removed for upgrading.

Shale Oil Upgrading

The second stage of oil shale processing is upgrading the shale oil recovered from the retorting step.

Shale oil upgrading is common to all oil shale technologies and is similar to the initial stages of crude oil refining. Upgrading is accomplished near the retorting site. Steps involved in the upgrading include oil recovery and fractionation, gas recovery and treating, sulfur recovery, heavy fractions cracking, naphtha and gas oil hydrotreating, ammonia separation, delayed coking, and water treating. Although the effluent stream from each type of retort differs, the same upgrading processes can be used for each retorting procedure. A detailed description of a typical shale oil upgrading sequence can be found elsewhere (RA-150). Regardless of the retort types, all processes utilize cracking and hydrotreating processes to upgrade the retort oil to distillate fuel quality.

SECTION VI.

IDENTIFICATION OF EMISSIONS AND IMPACTS

COAL EXTRACTION

Coal mining operation and equipment choices are extremely varied and in general are determined by the local geology and other natural conditions. As a result no single mining procedure can be presented as representative of the entire industry. The exact environmental effects will therefore depend upon the chosen mining technique and the prevailing geological and geochemical characteristics. In the following sections the environmental impacts of the different mining methods are discussed, followed by a general discussion of acid mine drainage which, although more prevalent for underground mining, is common to both surface and underground mining. To facilitate comparison, estimates are based whenever possible upon the production of 10^{12} Btu/day of primary fuel product. The primary fuel product in the mining modules is assumed to be run-of-mine (R.O.M.) coal.

Underground Coal Mining

The main environmental problem of underground coal mining is acid mine drainage. The average output of acid mine water per ton of coal produced in 1970 in the Appalachian bituminous coal mining region was calculated to be 353 gallons per ton of mined coal. This environmental problem will be discussed in more detail in the section on acid mine drainage.

Land Disturbance

Land requirements for any mining operation include the space occupied by the mine site itself and by processing and loading facilities. Underground mining also requires surface space for waste disposal in the form of refuse piles. The effects of solid waste disposal other than land use will be discussed in more detail below. The land used or disturbed by underground mining has been estimated to average 0.00034 acres per ton of coal mined (HI-083).

Subsidence is another form of land disturbance associated with underground mining. Improved mining techniques have increased the percentage of coal recovered and have therefore left less support at mine level in the form of remnant pillars. Subsidence of the ground surface due to the loss of subsurface support has resulted in a large amount of damage to property in some areas (AC-010). Although three years are required to reclaim surface-mined land in Illinois, an additional two years are allocated to underground-mined land prior to the start of reclamation activities to allow for subsidence (RA-150). Mining subsidence can affect ground water, alter hydrological conditions, affect water utilization, and create drainage problems (WO-035).

Water Effects

Process water requirements for underground mining operations include that used for dust control in the crushing plant and along haul roads. If physical cleaning facilities are located on site, these will also require water. This will be discussed in a section on physical coal cleaning. Water effluents are generally acid mine drainage from the mine site itself and run-off from refuse piles. The water pollution from refuse consists of acid mine drainage and siltation. TABLE 9 lists water quality data from four refuse sites. This data illustrates the variability of effluent from refuse (MA-411).

Table 9. WATER QUALITY DATA FROM SELECTED REFUSE SITES (SOURCE: MA-411)

Parameter	Luzerne County Penna.	Pike County Ky.	Muhlenburg County Ky.	Sullivan County Ind.
pH	3.0	6.9	2.5	2.4
Conductivity	4400	880	6800	6400
Acidity*	690	7	7020	6500
Alkalinity	-	135	-	-
Sulfate (SO_4)	3000	690	7800	9500
Sodium (Na)	100	115	270	200
Magnesium (Mg)	250	26	195	285
Aluminum (Al)	87	1.8	440	340
Potassium (K)	4.8	8.1	13	3.0
Calcium (Ca)	340	50	300	350
Manganese (Mn)	50	3.5	72	120
Iron (Fe)	30	6.2	3400	2600
Nickel (Ni)	1.7	-	3.0	1.6
Copper (Cu)	0.14	-	-	0.16
Zinc (Zn)	2.8	0.1	8	7.2
Lead (Pb)	-	-	0.12	0.30

*Acidity to pH 7.3

Notes:

(1) All values expressed in milligrams/liter (mg/l) except pH in standard units and conductivity in ohm^{-1}-cm^{-1}.

(2) Data taken from single grab samples taken in April and May 1974.

Solid Wastes

Solid wastes are generated during underground mining, crushing, and washing processes. Mine disposal of underground mining refuse is generally not practiced. Solid wastes are produced in an Illinois underground mining operation at a rate of 99.3 tons per 10^{12} Btu coal extracted (HI-083, footnote 1350). These solid wastes are found in refuse piles and present both air and water pollution hazards.

Refuse piles can ignite spontaneously and are difficult to quench. The U.S. Bureau of Mines examined 292 burning coal refuse piles throughout the nation's coal-producing regions in 1968. These coal waste fires, extending over 3,200 acres, produced particulate matter and fumes high in sulfur oxides. This posed a threat to health and safety in surrounding areas, damaged vegetation, and caused the deterioration of nearby structures (MC-096).

Refuse piles also cause water pollution in the form of acid mine drainage and siltation. Siltation is influenced by the steepness, compaction, drainage control structures, and cover material of the pile (MA-411). Refuse piles are also aesthetically displeasing.

The U.S. coal waste disposal problem is largely limited to the eastern coal fields where past practices have resulted in refuse piles that adversely affect the region's air and water quality and human health conditions (AT-052).

Air Emissions

Air emissions for underground mining operations are based on a previously developed room-and-pillar mining module (CA-246). Longwall mining emissions should be approximately equivalent to room-and-pillar emissions. A physical coal cleaning operation is included in calculating the emissions.

The basis for the room-and-pillar coal mining module is a cleaned coal production rate of 5,000 tons per day. Assuming a 20 percent waste removal in the physical coal cleaning operation and a thermal dryer fuel demand of 1.3% of the thermally dried coal, the run-of-mine coal is determined to be 6,300 tons per day. In 1972, 70% of all coal mined underground was mechanically cleaned (US-144). A summary of the emissions from the room-and-pillar mining module is shown in TABLE 10. Two sets of emissions are presented for the room-and-pillar mine. The difference between the two is the inclusion of emissions from burning refuse piles in one set. Figure 50 is a schematic of the mining operation.

The following assumptions are used in establishing the room-and-pillar module:

(1) The coal mine emits methane at a rate of 200 ft^3/ton of coal mined (DE-148).

(2) Ventilated air dust emissions will meet the Federal effluent air quality standard concentration of 2.0 milligrams per cubic meter (mg/m^3) (HI-097).

TABLE 10. SUMMARY OF ATMOSPHERIC EMISSIONS (SOURCE: CA-246)

Room and Pillar Mining Coal Module
Basis: 6,300 ton/day R.O.M. Coal

Air Emissions	lb/day	lb/day*
Particulates	936	12,700
SO_2	1,290	18,900
NO_x	690	6,490
CO	88.2	35,300
Hydrocarbons	43,200	59,100

*Includes emissions from burning refuse piles.

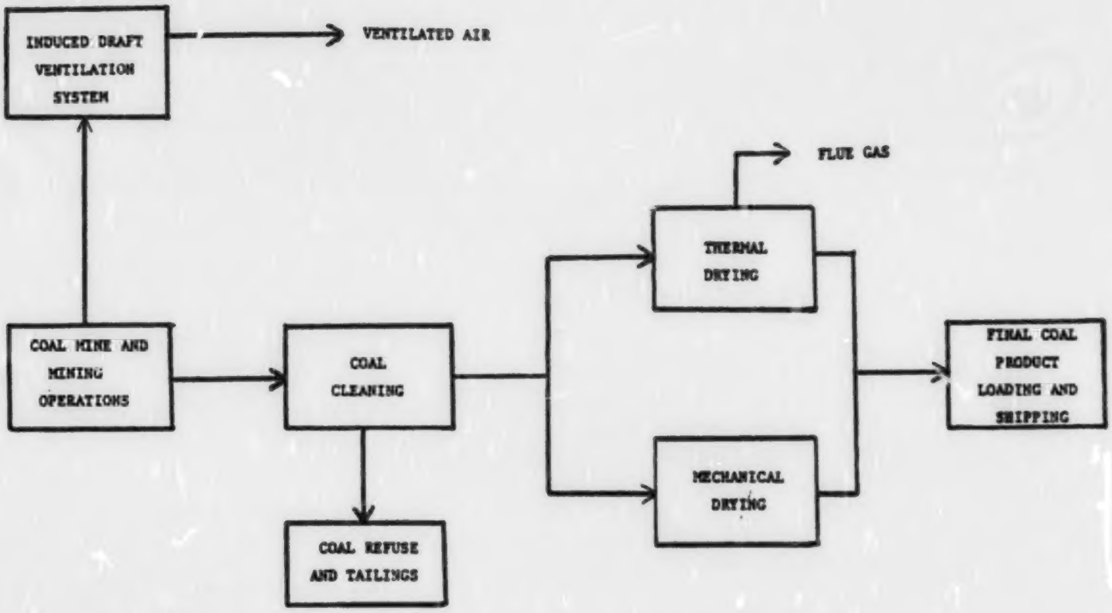

INDUCED DRAFT VENTILATION SYSTEM
VENTILATED AIR
FLUE GAS
THERMAL DRYING
COAL MINE AND MINING OPERATIONS
COAL CLEANING
FINAL COAL PRODUCT LOADING AND SHIPPING
MECHANICAL DRYING
COAL REFUSE AND TAILINGS

Figure 50. Room and pillar coal mine.

(3) The run-of-mine coal has a heating value of 12,000 Btu/lb and a sulfur content of 3.0 wt.% (HI-083).

(4) Twenty percent of the run-of-mine coal is removed as ash refuse in the coal cleaning operation.

These values are based on national averages.

In the room-and-pillar mine module there are six possible sources of air emissions: (1) mine ventilation system, (2) thermal dryer, (3) final coal product loading operations, (4) refuse transfer system from the preparation plant, (5) diesel-powered vehicles, and (6) refuse burning. The module emissions from the various sources are shown in TABLE 11.

TABLE 11. MODULE EMISSIONS FOR ROOM AND PILLAR COAL MINE (SOURCE: CA-246)

	Emissions (lb/day)				
Source	Particulates	SO_2	CO	Hydrocarbons	NO_x
Ventilated Air	180	-	-	53,200	-
Thermal Drying*	505	1,280	35	17	603
Coal Loading*	18	-	-	-	-
Transfer & Refuse	230	-	-	-	-
Vehicle Emissions	3.1	6.4	53.2	10.4	87
Burning Refuse	11,750	17,600	35,200	5,850	5,800
ROUNDED TOTAL	12,700	18,900	35,300	59,100	6,500

*99% controlled if wet scrubber used.

Note:

Basis: 6,300 ton/day R.O.M. Coal

The emission factors for burning refuse piles given in Table 12 are calculated from 1968 data on burning refuse piles (US-144, CO-168). The emissions from refuse piles are not necessarily related to a refuse production rate, but rather to the total amount of refuse accumulated. The emission factors in TABLE 12 are based on average values.

TABLE 12. EMISSION FACTORS FOR BURNING REFUSE PILES (SOURCE: CO-168, US-144)

Pollutant	Emission Factor (lb/ton of Refuse)
CO	17.8
NO_x	2.95
Hydrocarbons	2.95
SO_2	8.89
Particulates	5.94

It should be emphasized that these values are based upon national averages. The true emissions for any given mine will, of course, vary depending upon the coal region and such coal characteristics as the heating value per ton. Details of the above air emissions are found in reference CA-246. Comparisons to other energy extraction processes are given in TABLE 13 on the basis of 10^{12} Btu/day.

Other Environmental Factors

Blasting can fracture rock strata and create fissures in the bed rock, causing acid or saline pollution of the ground water. Blasting can also disrupt the flow of water to aquifers and create noise and vibration problems.

In 1971 the U.S. Bureau of Mines reported the results of an environmental noise survey made to determine the noise levels to which underground coal miners are exposed. The investigation revealed that the shift exposures of 20 percent of the miners studied were in excess of the safe standards (LA-048).

Surface Mining

The principal environmental effects of surface mining operations are mine drainage and land disturbance. Among the adverse environmental effects of surface mining of coal are (BA-234):

(1) destruction of the vegetative covering

(2) creation of massive piles of spoils

(3) drastic reshaping of the terrain

(4) sliding of spoils and blockage of streams

(5) pollution of streams with sulfuric acid and silt

(6) destruction of economic and aesthetic value of the land.

However, emphasis has been shifting to surface methods as demands for clean air have increased mining activities in low-sulfur strippable coal deposits in the western United States. Pollution problems arising from these operations will differ considerably from those in eastern coal regions. Pollution from western mining is not well characterized.

The pollution from area mines generally is not as severe as that from contour mines because silt from erosion can often be confined to the mining area (GR-156). Contour mining creates more possible environmental hazards such as sediment slides, exposure of toxic materials, land disturbance, and acid mine drainage. Auger mining disturbs less surface area than either contour or area mining but may provide access to underground mines for the entrance or exit of water, creating a source of acid mine drainage.

TABLE 13. COMPARISON OF EMISSIONS FROM EXTRACTION MODULES (SOURCE: CA-246)

	Air Emissions, lb/day							
	Coal Extraction					Oil Shale Extraction		
Pollutant	Strip[1]		Room and Pillar[2]		In-Situ[3]	Surface[4]	Room and Pillar[5]	In-Situ[6]
Particulates	11,900	(15,200)	6,190	(84,000)	5,500	64,800	13,100	127
SO_2	251	(8,730)	8,530	(125,000)	NA	640	35.7	239
CO	2,100	(2,490)	583	(233,000)	30,000	5,400	307	414
NO_x	3,440	(7,670)	4,560	(42,900)	NA	8,800	504	19.6
Hydrocarbons	397	(542)	352,000	(391,000)	65,000	1,000	57.1	718

[1] Adjusted from 6,300 tpd run-of-mine coal (12,000 Btu/lb). Emissions in parentheses include emissions from physical coal cleaning.

[2] Adjusted from 6,300 tpd run-of-mine coal (12,000 Btu/lb). Mining emission values include emissions from physical coal cleaning. Emissions in parentheses include emissions from burning refuse piles.

[3] Adjusted from 10 Btu/day fuel gas produced. Data on SO_x and NO_x emissions were not available (NA).

[4] Adjusted from 50,000 bbl/day of upgraded shale oil capacity (5.6×10^6 Btu/bbl).

[5] Adjusted from 50,000 bbl/day of upgraded shale oil capacity (5.6×10^6 Btu/bbl).

[6] Adjusted from 50,000 bbl/day of upgraded shale oil capacity (5.6×10^6 Btu/bbl).

Note:

Basis: 10^{12} Btu/day Fuel Output.

Land Disturbance

The average amount of land used or disturbed by surface mining is 0.0003 acres/ton of coal mined (HI-083). The actual amount of land used varies from one geographical region to another depending upon such factors as the coal seam thickness and overburden thickness. For a typical western U.S. strip mine, less than an acre of land is disturbed to produce 10^{12} Btu of run-of-mine coal. Nearly seven acres are disturbed by strip mining for Illinois coal. The difference is due to the much greater thickness of the western U.S. coal seams (RA-150).

In addition to the mine site itself, land requirements for a mining operation will include the space occupied by processing and loading facilities, haul roads, and reclamation activities.

Solid Wastes

No solid wastes are assumed to be generated as a result of surface mining operations since waste solids can be returned to the mine and disposed along with overburden material. This, of course, depends upon maintenace of land reclamation as an integral part of the mining operation. If reclamation is not practiced, toxic materials may be exposed to the environment. Removal and placement of the overburden are critical in environmental control. The nontoxic, nonacid, and fertile material should be stockpiled for later spreading or placed on the less desirable spoils already mined (GR-156).

Water Effluents

The only process water requirements are the water used for dust control in the crushing plant and along haulage roads. Reclamation water requirements may be significant in the case of western surface mining (NA-172).

The coal deposits of the western United States are located in arid to semi-arid regions, and coal seams are generally aquifers and principal sources of fresh water. Mining may therefore cause alteration of ground water distribution by aquifer disruption (GR-156).

In strip mining, natural drainage channels are often interrupted. Unless the water is diverted around the mine, it enters the mine and becomes a possible pollution source. Cutting into abandoned or inactive underground mines can result in the discharge of large volumes of stored polluted water (GR-156).

Mine drainage from surface mining may cause serious pollution in a physical form such as sediment, or in a chemical form such as acid mine drainage, or in a combination of both forms (GR-156). Significant pollutants are silt, sulfuric acid, iron, and trace elements such as arsenic, copper, lead manganese, and zinc (BA-234).

Sediment and Erosion

Sediment causes more off-site damage than any other aspect of strip mining. Indiscriminate dumping of overburden on the downslope during contour mining and on coal haul roads contributes to stream sedimentation from strip mining.

Sediment can destroy crops and farmland, damage buildings, cause flooding, decrease stream and reservoir capacities, and seriously degrade water quality by destroying habitats for aquatic life and increasing the toxic content of water sources.

Strip mining accelerates the natural processes of erosion and sedimentation. With the removal of ground cover, water flowing through a mining area removes soil and creates gullies. The susceptibility of strip-mined land to erosion depends on (1) physical characteristics of the overburden, (2) degree of slope, (3) length of slope, (4) climate, (5) amount and rate of rainfall, and (6) type and percent of vegetative ground cover (GR-156).

Air Emissions

Air emissions for surface mining operations are based on a strip mining module (CA-246). Auger mining emissions should be approximately equal to strip mining emissions.

The strip mine module is examined for mining without physical coal cleaning and with physical coal cleaning. The module basis is 5,000 tons per day of cleaned coal. A 20 percent waste removal in the physical coal cleaning operation and a thermal dryer fuel demand of 1.3 percent of the thermally dried coal are assumed. Run-of-mine coal is used for the module without coal cleaning. The equivalent coal production rates allow convenient comparison of module emissions. In 1972, 31.6 percent of all the coal extracted by strip mining was mechanically cleaned (US-144). A summary of emissions from both of the strip mining modules (with and without physical cleaning) is shown in TABLE 14.

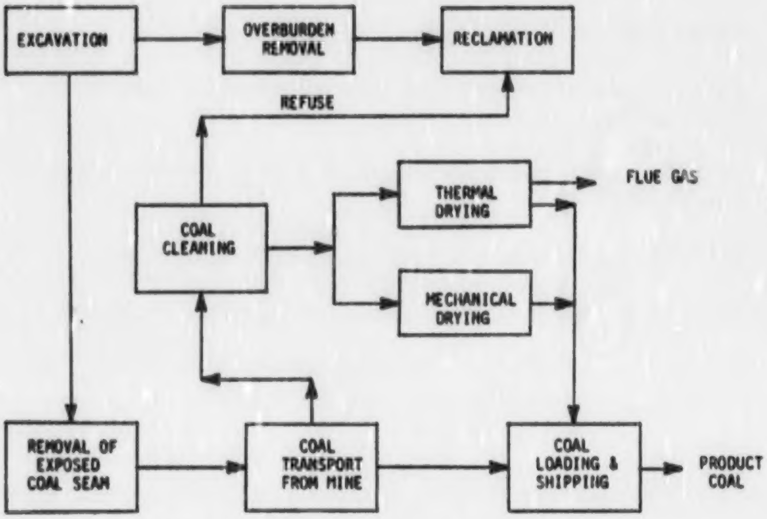
TABLE 14. SUMMARY OF ATMOSPHERIC EMISSIONS:
STRIP MINING COAL MODULE
(BASIS: 6,300 TON/DAY R.O.M. COAL)
(SOURCE: CA-246)

Air Emissions (lb/day)*	Without Physical Coal Cleaning	With Physical Coal Cleaning
Particulates	1,800	2,300
SO_2	38	1,320
NO_x	520	1,160
CO	317	376
Hydrocarbons	60	82

---

*The difference in air emissions results from the thermal dryer and diesel-powered equipment associated with the physical cleaning operation.

The strip mine module is considered to be in steady-state operation. This means that the mine pit has already been opened and the mine is in production. In this module, any overburden excavated on a continuous basis is moved to the rear of the mine and refilled as a reclaiming operation. The coal strip mine module is shown in Figure 51.



EXCAVATION
OVERBURDEN REMOVAL
RECLAMATION
REFUSE
THERMAL DRYING
FLUE GAS
COAL CLEANING
MECHANICAL DRYING
REMOVAL OF EXPOSED COAL SEAM
COAL TRANSPORT FROM MINE
COAL LOADING & SHIPPING
PRODUCT COAL

Figure 51. Strip mining coal module.

Assumptions used in the strip mining modules include the following:

(1) The preparation plant is located 3.0 miles from the coal production site (ST-166).

(2) The average depth of overburden is 48 feet and has a density of 100 pounds per cubic foot (HI-083).

(3) The average coal seam is 5.2 feet thick and has a density of 81 pounds per cubic foot (HI-083).

(4) A typical strip mine pit is 100 feet wide by 2,000 feet long (HI-083).

(5) The run-of-mine coal has a heating value of 12,000 Btu/lb and a sulfur content of 3.0 weight percent (HI-083).

(6) 20 percent of the run-of-mine coal is removed as ash refuse in the coal cleaning operation.

These values are based on national averages. Emissions related to specific coals will vary from the emissions presented in this section depending on coal quality and physical layout of the plant. Western coals have a lower quantity of ash associated with the coal (less than 10 percent ash).

A strip mining operation without a mechanical cleaning facility would probably be used for low ash and low sulfur western coal.

Four possible sources of air emissions are associated with the strip mining module. They are as follows:

(1) Emissions from diesel-powered vehicles

(2) Particulate emission from the preparation plant and loading facilities

(3) Fugitive dust emissions from the operations within the mine

(4) Emissions from thermal drying (if used).

Emissions from the various sources are given in TABLE 15.

TABLE 15. MODULE EMISSIONS
(STRIP COAL MINING MODULE
BASIS: 6,300 TON/DAY R.O.M. COAL)
(SOURCE: CA-246)

Source	Particulates	Emissions (lb/day)			
		SO_2	CO	Hydrocarbons	NO_x
Vehicle Emissions	18.3	38	317	60	520
Overburden Removal*	1160	--	--	--	--
Primary Crushing*	126	--	--	--	--
Loading and Unloading Plant at the Preparation	39	--	--	--	--
Loading in the Pit*	506	--	--	--	--
Vehicular Travel*	40	--	--	--	--
Thermal Drying**	505	1290	35	17	603
Vehicle Emissions from Refuse Hauling Operations	1.4	2.9	24	4.5	39
ROUNDED TOTAL	2,400	1,300	380	82	1,200

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* 80 percent particulate control by water spraying and dust control techniques.

**90 percent particulate control by wet scrubbers.

Details of the calculations of the air emissions are given in Reference CA-246.

Comparisons to other energy extraction processes are given in Table 13 on the basis of 10^{12} BTU/day.

Other Environmental Factors

Blasting can fracture rock strata and create fissures in the bed rocks, causing acid or saline pollution of the groundwater. Blasting can also disrupt the flow of water to aquifers, and create noise and vibration problems (GR-156).

Surface mining is also aesthetically displeasing because of the land disturbance and unsightly spoil banks.

Acid Mine Drainage

Acid mine drainage, a significant environmental problem of coal mining, results when naturally occurring pyrite (FeS_2) in the coal seam and wastes is oxidized in the presence of air and water to form sulfuric acid and soluble iron [Fe(II) and Fe(III)] sulfates. Such mine drainage is typically very acidic (pH 2 to 3) and must be treated for pH and dissolved iron before release to surrounding water courses. At these low pH's, heavy metals (e.g., iron, manganese, cadmium, copper, zinc, lead, etc.) are more soluble and create further water pollution problems.

The acid drainage of bituminous and anthracite coal mines in the United States has been a major source of inorganic pollution to the streams in these mining areas. Increased demands for water has made the deteriorated water quality caused by these wastes more noticeable (CL-044).

Continuous acid discharges have a serious effect on aquatic ecosystems. Acid waters containing high concentrations of dissolved heavy metals support only limited water flora, such as acid-tolerant molds and algae, and will not support fish. In 1967, more than a million fish were killed by mine drainage, ranking this type of pollution as one of the primary causes of fish kills in the United States (ST-149). Such water also corrodes metal structures, harms municipal and industrial water supplies, and makes water unfit for recreation.

The amount and rate of acid formation and the quality of water discharged are functions of the amount and type of pyrite in the overburden and in the coal, time of exposure, characteristics of the overburden, and amount of available water (MO-141). Acid mine drainage is less of a problem in the arid, western coal mining regions where the sulfur content of the coal is less, but represents a significant environmental problem in portions of the Appalachian region (BI-014). The average output of acid mine water produced in the Appalachian bituminous coal mining region in 1970 was calculated to be 353 gallons per ton of coal mined (BA-234).

Coal mine refuse can also be a source of acid drainage. Acid runoff from refuse piles can be controlled by covering the wastes with soil, establishing a vegetative cover, and providing adequate drainage to minimize erosion (KO-105).

The best method for preventing acid mine drainage is good planning, mining, and reclamation. The amount of time wastes are exposed should be minimized to prevent pyrite oxidation. Water contact with the mine area should be minimized to reduce the water available for flushing oxidation and erosion products (GR-156).

If acid mine drainage cannot be prevented or the discharge controlled, the water must be neutralized. Most treatment processes involve (1) neutralization, (2) aeration, (3) sedimentation of precipitated solids, and (4) sludge disposal. Alkaline reagents that may be used are ammonia, sodium carbonate, sodium hydroxide, limestone, and lime.

The advantages and disadvantages of neutralization are given in Table 16. Neutralization has its own environmental impacts because the water still contains large amounts of dissolved solids and a sludge must be disposed.

Neutralization and sludge disposal techniques are objects of continued research (AK-006, BI-014, BI-047, DA-077, PH-038). No single dewatering system has been found best for all acid mine drainage sludges (AK-006). The nature of sludge, disposal techniques, sludge conditioning, dewatering techniques, and sludge banding were discussed in a comprehensive report on solid waste disposal. Three case studies of acid coal mine drainage treatment plants are included in the study.

Underground Gasification

Present work in underground coal gasification has been in experimental and developmental stages. Environmental data on these in-situ processes is very limited. Moreover, on the basis of technical and economic experience to date, it is difficult to foresee when commercial operations will be a reality.

Land disturbance by underground gasification will be much less severe than by strip-mining and surface gasification. It will require much less land space for surface facilities. The ash from underground gasification will remain underground. The amount of surface subsidence will vary with the seam thickness of the gasified coal, the depth of the coal, and the nature of the strata overlying the coal (HU-079).

Potential environmental problems associated with underground gasification are ground-water pollution and leakage of toxic gases such as carbon monoxide. There is the possibilty that ground-water pollution similar to acid mine drainage may be caused by the entrance of ground water into coal seams depleted by gasification (HU-079).

The only anticipated air emissions from underground coal gasification are fugitive emissions from high pressure equipment and from vehicular movement around the surface facilities. However, if an underground gasification process becomes commercial, gas cleaning procedures would probably be used.

TABLE 16. ACID MINE DRAINAGE NEUTRALIZATION
(SOURCE: GR-156)

Advantages	Disadvantages
(1) Neutralization removes acidity	(1) Hardness is not reduced and may be increased.
(2) Neutralization removes heavy metals; as the pH increases, the solubility of heavy metals decreases.	(2) Sulfate is usually not reduced to a low level and usually exceeds 2,000 mg/liter.
(3) Ferrous iron is removed as ferric iron at higher pH levels.	(3) Iron concentration is not usually reduced to less than 3 to 7 mg/liter.
(4) Sulfate can be removed. In highly acidic acid mine drainage, it may be necessary to add enough calcium iron to exceed the solubility of calcium sulfate.	(4) Total dissolved solids concentration is increased.
	(5) A waste sludge to be disposed of is produced.

COAL CLEANING

Physical Coal Cleaning

The environmental consequences of physical coal cleaning have been examined by Radian (RA-150), Hittman (HI-083), Battelle (BA-234), and the University of Oklahoma (UN-025). Some aspects of physical coal cleaning were discussed in the previous section on underground mining.

Most studies have examined the type of coal cleaning process previously described. However, other processes in various stages of development may become environmentally important. One of these is an oil agglomeration process in which substantial amounts of many trace elements are removed from the coal during beneficiation (CA-152). These elements are concentrated in the tailings from the coal cleaning plant. This removal diminishes the potential for adverse effects from coal combustion, but the refuse from the cleaning facility must therefore be more carefully controlled.

Water and land estimates for a physical coal cleaning facility vary widely (UN-025). Some water requirements are estimated to be as high as 1,500 to 2,000 gallons per ton of coal processed (BA-234, UN-025), while others are as low as 524 gallons per ton (UN-025). Land requirement estimates vary from 90 acres including settling ponds (BA-234, UN-025) to 400 acres including settling ponds (UN-025).

Ultimate analyses of Illinois coal, both before and after cleaning, are given in Table 17. The ash and sulfur concentrations of the coal are reduced by cleaning. These components will be in the water effluents and solid wastes.

TABLE 17. ULTIMATE ANALYSES OF AN ILLINOIS COAL
(SOURCE: RA-150)

	Before Cleaning	After Cleaning
C	61.0	65.2
H_2	5.2	5.6
N_2	1.4	1.1
O_2	6.8	7.7
S	3.6	2.1
Ash	11.0	6.9
H_2O	11.0	11.5
	100.0	100.1
Heating Value	11,000	11,500

Note: All numbers are wt % except heating value which is Btu/lb coal.

If proper pollution controls are not implemented, water pollution at a cleaning facility may result from discharged process water or runoff from refuse piles. This water may contain acid, suspended solids, and dissolved solids. Although water streams within the coal-cleaning process may contain high levels of suspended and dissolved solids, all liquid waste streams are routed to holding ponds to allow settling of the suspended solids. The clear supernatant liquid is then recycled to the process. Thus, no liquid effluents result from the cleaning process.

Solid wastes from the coal cleaning process result from a loss in process feed. The amount of solid wastes depends upon the operating conditions but will be in the range of 10 to 21 pounds per 10^6 Btu of plant output (BA-234).

Any solid waste that cannot be returned to the mine site for disposal will accumulate in refuse piles.

Air emissions from the coal-cleaning process are rather limited. Particulates may be emitted during the handling process. Coal burned to operate thermal dryers may release some particulates such as NO_x, SO_2, and CO. New coal cleaning plants are assumed to be completely enclosed and to utilize baghouses to control particulate emissions. Spontaneous ignition of refuse piles may also release noxious emissions of SO_2, NO_x, and hydrocarbons.

Chemical Coal Cleaning

The technical feasibility of chemical coal cleaning has been established, but the economic feasibility is still to be proven. Both the Meyers and Battelle processes have been tested at bench-scale and pre-pilot plant levels. Because they are still in developmental stages, there is little direct information about the environmental effects of these processes.

The Meyers' process contains the following probable sources of wastewater, air pollution, and solid wastes (BA-234):

(1) Spent leachate solution from leaching circuit

(2) By-product iron sulfate from leaching circuit

(3) Elemental sulfur from sulfur recovery circuit

(4) Solvent-vapor loss from sulfur recovery circuit.

An evaluation of pollution control has been conducted for the Meyers' process (MA-473). Effluent streams, process alternatives and improvements, and technology needs were identified. It was noted that the large quantity of iron sulfate to be disposed of creates a potential problem and the purge-water streams need to be better defined with respect to dissolved solids and organics. The buildup of potentially hazardous trace elements in the treatment plant was cited as a possible problem. Although the leaching of trace elements is beneficial with respect to utilization of the product, the leaching concentrates these elements in a small area. Disposal techniques therefore are more important. Another important finding in the above evaluation was that some coal, even after treatment, may still have an unallowable sulfur concentration.

The hydrothermal process by Battelle contains the following four probable sources of wastewater, air pollution, and solid wastes:

(1) Spent solution that cannot be recycled because of a buildup of impurities

(2) Fugitive emissions of hydrogen sulfide and sulfur dioxide from the sulfur recovery circuit

(3) Particulate emissions from grinding step

(4) By-product sulfur.

The hydrothermal process extracts several potentially hazardous metals from coal (e.g., beryllium, arsenic, barium, and lead) which, if not removed, might be emitted into the air during coal combustion. This is a favorable impact in the utilization of the coal, but it also means that the effluent streams in the cleaning process must be carefully controlled so that the impacts of these metals will not be transferred to a new location.

COAL SLURRY PIPELINE

The impending expansion of the nation's coal slurry pipeline system necessitates a consideration of the ensuing environmental effects. The Coal Pipeline Act of 1974 is designed to facilitate the construction of coal pipelines. This act amended the law governing issuance of rights-of-way over Federal lands for oil and gas pipelines to include coal pipelines. The environmentally responsible Federal law applicable to rights-of-way now applies to coal pipelines on Federal lands. The act also authorizes the Federal Power Commission (FPC) to give a right of eminent domain over private property to the operator of a coal pipeline after the operator meets standards and obtains an FPC certificate (CO-197). The granting of rights-of-way for the proposed Wyoming-Arkansas coal pipeline is presently a controversial matter in certain Midwestern states.

TABLE 18 summarizes the environmental effects and corresponding mitigation procedures encountered in building a coal slurry pipeline. The effects are basically the same as for any major pipeline. Generally the land at any point should be disturbed by construction for only 2 to 6 weeks. When the construction is finished, revegetation and other forms of reclamation should begin.

TABLES 19 and 20 summarize the primary and secondary environmental impacts of coal slurry pipeline systems. Operational impacts are associated with the following three areas: (1) coal preparation, (2) main slurry pipeline and pump stations, and (3) dewatering systems (GR-177). Except for the disposal of slurry water, the environmental effects of the dewatering system are similar to those for coal preparation. If not used as process water or if improperly disposed of, this water could be an environmental problem.

Because future development of energy resources will be concentrated in the western regions of the United States, manpower requirements should be considered in environmental assessments. Coal slurry pipelines require relatively few operating and maintenance personnel. The Black Mesa pipeline system requires only 55 men (MO-113). Coal slurry pipelines allow the coal processing or utilization facilities to be removed from the source and placed closer to urban centers where the relative socio-economic impact on the surrounding community will be lessened.

Slurry pipelines have an esthetic advantage over other modes of coal transportation. Although the preparation plant, pumping stations, and dewatering plant are above ground, the pipelines are buried 2½ to 3 feet underground and therefore out of sight.

TABLE 18. ENVIRONMENTAL EFFECTS OF COAL PIPELINE CONSTRUCTION ACTIVITIES (SOURCE: GR-177)

Activity	Environmental Effects	Mitigation Measures
(1) Clearing and grading	Destroys wildlife habitat Encourages runoff and erosion Degrades esthetics	Revegetate quickly Slow runoff Leave screening vegetation
(2) Ditching	Potential runoff from spoil pile Covering top soil may produce rock rubble	Close ditch as soon as possible Separate top soil and set aside Haul to appropriate disposal site
(3) Hauling and Stringing Pipe	Increased truck traffic	Limit haul hours and route
(4) Welding Pipe	None	None
(5) Coating Pipe	Accidental spill of coating materials	Normal care in operation and availability of cleanup materials
(6) Backfill	Extra top soil or ditch "padding" soil may be needed	Use existing or properly sited borrow pits
(7) Clean-up	Erosion of right-of-way	Adequate revegetation program Restore drainage patterns Monitoring of recovery
(8) Testing System	Requires large volumes of water	Careful selection of water source and discharge

The risk of spills from coal slurry pipelines is considered to be slight. The control and prevention of pipeline corrosion is a developed technology because of extensive work with petroleum, natural gas, and other underground pipeline systems. Particle attrition and significant pipeline wear should be negligible in long-distance coal slurry pipelines because the particles are in turbulent flow and in suspension rather than saltating along the bottom of the pipe. No measurable particle attrition has been observed with either the Consolidated Coal Company system or the Black Mesa pipeline system (WA-127).

TABLE 19: PRIMARY ENVIRONMENTAL ASPECTS OF COAL SLURRY PIPELINE SYSTEMS

(SOURCE: GR-177)

SYSTEM COMPONENTS	ENVIRONMENTAL ASPECTS	MITIGATING MEASURES
Well water field and collection system	Possible changes in ground and surface water use. Possible land use changes. Accidental water release.	Regulation of quantity and use of water and coordinate water needs with existing water use plans and policies. Coordinate water use changes with existing regional land use plans and policies. Develop back-up safety system.
Water pump station	Noise. Power use.	Design and shield unit to minimize noise. Unavoidable.
Water supply pipeline	Accidental water release.	Develop back-up safety system.
Coal cleaning system	Noise. Water use. Fugitive dust. Power use.	Design and shield unit to minimize noise. Design system to reduce water loss. Design air pollution control system(s). Unavoidable.
Slurry preparation system	Noise. Water use. Fugitive dust. Accidental slurry release. Power use.	Design and shield unit to minimize noise. Design system to reduce water loss. Design air pollution control system(s). Develop back-up safety system. Unavoidable.
Slurry pipeline	Accidental slurry release. Land clearing.	Develop back-up safety system. Revegetate.
Slurry pump stations and related facilities	Noise. Water use. Power use. Accidental slurry release. Slurry storage containment failure.	Design and shield unit to minimize noise. Design system to reduce water loss. Unavoidable. Develop back-up safety system. Develop back-up safety system.
Dewatering system	Noise. Fugitive dust. Water use. Power use. Accidental slurry release. Slurry storage containment failure. Water quality from dewater process.	Design and shield unit to minimize noise. Design air pollution control system(s). Design system to reduce water loss. Unavoidable. Develop back-up safety system. Develop back-up safety system. Design storage and treatment facilities.

TABLE 20. SECONDARY ENVIRONMENTAL ASPECTS OF COAL SLURRY PIPELINES (SOURCE: GR-177)

System Components	Environmental Aspects	Mitigating Measures
Coal Supply (Coal Mining Development)	Water use.	Regulate mining to meet water use and water quality standards.
	Land use.	Observe mined land reclamation rules and regulations.
	Socioeconomic change.	Analyze community conditions and recommend community development strategies related to increased mineral development.
Population Increase	Housing demand and community facility demand.	Inventory community capacity and recommend housing and community development strategies.
Power Use	Economic and population growth.	Analyze future regional energy supply and demand characteristics and recommend regional economic and population development strategies.

Assessments of the environmental effects of coal slurry pipelines have been made for a pipeline design of a specific capacity and a pipeline module with an equivalent throughput of 10^{12} Btu/day (RA-150). A 1,000-mile-long, 38-inch diameter pipeline is the example of a specific capacity; this size also corresponds very closely to a projected pipeline between Wyoming and Arkansas (EN-202). This size pipeline would be able to move 25 millions tons of Western United States coal per year. This is equivalent to 1.21×10^{12} Btu/day of energy transported, based on a western coal heating value of 8806 Btu/lb. A coal slurry pipeline with an equivalent throughput of 10^{12} Btu/day is approximately 83% as large.

The environmental effects of an electrically-operated coal slurry pipeline system were computed on the basis of the following major assumptions (RA-150):

(1) A 1,000-mile-long, 38-inch diameter pipeline with an annual throughput of 25 x 10^6 tons of coal will be used (CO-129, HU-088, EN-202, WA-127)

(2) One pumping station every 100 pipeline miles will be installed (CO-129, HU-088)

(3) The required water (12 gallons/10^6 Btu) will be available

(4) Electrical energy equivalent to 300 x 10^9 Btu/100 miles-year will be used (AU-019)

(5) The pipeline system will be operational 365-days/year

(6) A heating value of 8806 Btu/lb for western coal will be met

(7) A thermal efficiency reduction of about 2% will occur as a result of the slurry water that remains in the boiler feed (HI-090, SO-039).

Assumptions 1 through 6 were applied to the specific coal slurry pipeline length called for in this study.

Some of the environmental effects of a 1,000-mile coal slurry pipeline system will change with the length of the pipeline. The parameters that will be affected are the ancillary energy and the land use. These parameters can be adjusted for any desired length of the pipeline, using an approach outlined in a previous report (RA-150).

The environmental effects of a 1,000-mile coal slurry pipeline and a 10^{12} Btu/day pipeline are summarized in TABLE 21 and discussed in the following sections.

Land Use

A land use of 14,000 acres for a typical 1,000 mile, 38-inch diameter coal slurry pipeline system includes acreage of several items, such as those shown below in TABLE 22 (CO-197, HU-088).

The coal slurry pipeline module requires 1.02 x 10^4 acres of land (RA-150).

With respect to land use, it should be remembered that the coal slurry pipeline will be buried 2½ to 3 feet underground.

Water Requirements

A typical coal slurry pipeline has a water requirement of 12 gallons of water per million Btu delivered (EN-202).

TABLE 21. SUMMARY OF ENVIRONMENTAL EFFECTS OF ELECTRICALLY-OPERATED COAL SLURRY PIPELINES (SOURCE: RA-150)

	Estimated Design* (1,000 Miles)	Module (10^{12} Btu/day**)
Air Emissions (lb/hr)	0	0
Water Emissions (lb/hr)	0	0
Thermal (Btu/hr)	0	0
Solid Wastes (tons/day)	0	0
Land Use (acres)	1.40×10^4	1.16×10^4
Water Requirements (gal/day)	1.45×10^7	1.20×10^7
Efficiency (%) (Primary)	98	98
Ancillary Energy (Btu/day)***	8.22×10^9	6.79×10^9

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* Based on an annual throughput of 25×10^6 tons of coal per year (1.2×10^{12} Btu/day) and a 1,000-mile, 38-inch pipe.

** Module based on energy transported.

***In the form of electric energy transported.

TABLE 22. LAND USE REQUIREMENTS FOR COAL SLURRY PIPELINE

Description of Use	Acres
Slurry Pipeline Right-of-Way (104-foot right-of-way)	12,550
Coal Preparation Plant	100
Dewatering Plant	200
Slurry Pipeline Pump Stations (10 stations)	470
Water Supply Gathering Pipeline Right-of-Way	610
Water Supply Pump Station	60
Water Supply Wellhead Facilities	10
TOTAL	14,000

Air Emissions

Since a coal slurry pipeline system is electrically operated, it does not directly produce any form of air emissions during its operation.

Water Emissions

Water used in the slurry transport is clarified and used as a part of the terminal process or power plant make-up water requirements (AU-019, CO-197, EN-140, EN-202, HU-088).

Experience gained from the Black Mesa coal slurry pipeline system indicates that the clear water from the settling tank contains about 25 ppm of coal solids (SO-039). The water quality is the major factor considered in deciding whether to use the water for cooling tower make-up, or ash handling, or to be discharged into evaporation ponds. The Black Mesa coal slurry pipeline provides about 15% of the plant water requirements (WA-153, EN-202).

In view of the foregoing discussion, it is concluded that a coal slurry pipeline does not discharge any form of pollutant that may degrade water bodies.

Thermal Emissions

A coal slurry pipeline system in operation does not produce significant thermal emissions.

Solid Wastes

Solid wastes in the form of coal solids of about 25 ppm in the clarified water are ultimately discharged into the evaporation ponds. Since these minute quantities of solid wastes are contained in the ponds, they do not produce any adverse effects in the environment.

COAL GASIFICATION

The purpose of coal gasification is to convert an environmentally unacceptable fuel into a clean, convenient gas which when used as a fuel will not degrade environmental quality. Consideration must be given to the environmental effects of gasification facilities which could be sizeable. The potential emissions may be greater than 1,000 ton/day from a plant producing 250 million scfd of SNG from high-sulfur coal (FE-068). Therefore, it is important not to transfer the environmental impact of conventional coal utilization facilities to that of coal gasification facilities. A careful assessment of coal gasification techniques is needed while most are still in the development stage. Information on the environmental impact of coal gasification is currently rather limited and general.

In the following sections, possible pollutants from gasification processes will be examined, high-Btu gasification, and low-intermediate-Btu gasification will be discussed in general terms, and aspects of individual processes will be discussed.

Potential Pollutants

The major concerns of gasification processes thus far have been with sulfur compounds and other criteria pollutants. However, the emissions of various trace pollutants, both organic and inorganic, may have to be controlled. The initial gasification step will largely determine the possible pollutants, whatever their fate in subsequent processing steps. Coal preparation, product processing, and on-site auxiliary fuel combustion will also contribute to the total amount of pollution.

A previous study (CA-204) has compiled an extensive list of specifically identified, potentially hazardous materials which may be associated with coal gasification. Potential pollutants were classified according to their chemical species and their potential for harmful impact. The listing is broken down into the different stages involved in gasification processes. Potentially hazardous trace organics and trace elements are included as well as more common species. It was determined that coal gasification is likely to produce substances as dangerous as those produced by a coke plant, but the substances produced by gasification will probably be more contained. It was also found that the quenching and cooling of gasifier off-gas and the tar separation unit are the most important potential sources of toxic emisssions in a coal gasification plant.

The thermal treatment of coal causes the formation of numerous organic compounds, many of which are potentially hazardous. For example, coke ovens thermally treat coal and emit several types of polynuclear aromatics, such as benzopyrene. The possible formation and fate of such organic compounds in gasification plants is largely unknown. Coal also contains many types of trace elements. The fates of the trace elements are not well established.

Gas streams in gasification facilities may contain sulfur dioxide, hydrogen sulfide, nitrogen oxides, ammonia, carbon monoxide, hydrocarbons, hydrogen cyanide, particulates, and odorous compounds. Process water streams may contain phenols, cresols, light aromatics (e.g. benzene-toluene-zulene compounds), oils, tars, ammonia, sulfur compounds, hydrogen cyanide, coal char, ash, and high molecular-weight organics.

The total quantity of potential emissions within major chemicals categories is illustrated below for a gasification plant producing 250 million scfd of pipeline gas from Illinois No. 6 coal (3.7% sulfur). Ranges are indicated because of variations between the different gasification processes and because of uncertainties in some yields (FE-068).

Sulfur (primarily as H_2S)	300-450 long tons/day
Ammonia	100-150 tons/day
Hydrogen Cyanide	0 to possibly 2 tons/day
Phenols	10-70 tons/day
Benzene	50-300 tons/day
Oils and Tars	Trace to 400 tons/day
Mercury	Less than 5 lb/day

Gasification operations produce a high-ash content residue of 1,000 to 3,000 ton/day or a char remainder of 4,000 to 5,000 tons/day. The CO_2 Acceptor Process will also contribute about 900 tons/day of spent dolomite.

The gasification of coal takes place in a closed system, which makes it easier to prevent the emission of pollutants to the atmosphere or water (NA-183). However, associated operations (e.g., coal handling and processing, gas purification, ash handling and disposal), presence of toxic pollutants, and fugitive emissions create potential environmental hazards and must be considered. The nature and magnitude of the pollution problems will depend on the coal to be used, its sizing, the disposition of fumes and dust, the gasification technique involved, and the pollution controls used.

Air Emissons

Because coal gasification occurs in a closed system, it should be easier to control the emission of pollutants to the atmosphere. However, processing steps, auxiliary equipment, and fugitive emissions present possibilities for air emissions, and it is important to know the possible gaseous compounds.

Important sources of emissions are fugitive losses from the gasification and processing steps. Fugitive emissions escape from sources such as valve stems, flanges, loading racks, equipment leaks, pump seals, sumps, etc. Because gasification facilities are closed systems the fugitive losses may be the major source of emissions. Gasification processes also operate under pressure which increases the potential for fugitive emissions. The assessment of fugitive emissions is difficult because there is no operating experience with gasification plants on the commercial scale envisioned for future use.

Sulfur dioxide, nitrogen oxides, particulates, and carbon dioxide will be the major emissions to the air. Sulfur dioxide emissions can come from the sulfur recovery plant tail gas and the stack gases of auxiliary combustion systems. In some instances it may be necessary to clean these stack gases by scrubbing, depending on the sulfur content of the combusted material. Emissions of nitrogen oxides are a result of fuel combustion in boilers and process heaters. Particulate matter can enter the atmosphere as fugitive dust from coal handling operations or as stack gas emissions from combustion or process unit operation. Carbon dioxide is also emitted to the air from the processing operations. Hydrocarbon emissions occur by evaporation of hydrocarbon liquid dissolved in liquid waste or in cooling streams, fugitive emissions, and incomplete combustion at auxiliary plant facilities. Carbon monoxide, although produced in large quantities during gasification, is principally emitted because of incomplete combustion in auxiliary facilities.

In addition to the large quantities of H_2, CO, CO_2, CH_4 and ethane (C_2H_6) made in the gasifier, a number of trace components also occur and are of interest. Sulfur compounds formed during all gasification processes are hydrogen sulfide, carbonyl sulfide, carbon disulfide, thiophenes, and mercaptans. Hydrogen sulfide is the predominant sulfur species. Light weight benzene-toluene-xylene (BTX) components are also formed. TABLE 23 gives the concentrations of these components in the gas stream of a Synthane gasifier (FO-026). Although these compounds should be removed in the processing steps, they may be discharged to the air by fugitive emissions, incomplete stripping of the process

TABLE 23. COMPONENTS IN GASIFIER GAS, PPM (SOURCE: FO-026)

	Illinois No. 6 Coal	Illinois Char	Wyoming Subbituminous Coal	Western Kentucky Coal	North Dakota Lignite	Pittsburgh Seam Coal
H_2S..................	9,800	186	2,480	2,530	1,750	860
Carbonyl sulfide (COS)	150	2	32	119	65	11
Thiophene............	31	.4	10	5	13	42
Methyl thiophene.....	10	.4	-	-	-	7
Dimethyl thiophene...	10	.5	-	-	11	6
Benzene..............	340	10	434	100	1,727	1,050
Toluene..............	94	3	59	22	167	185
C_5 aromatics.........	24	2	27	4	73	27
SO_2..................	10	1	6	2	10	10
Carbon disulfide(CS_2)	10	-	-	-	-	-
Methyl mercaptan.....	60	.1	.4	33	10	8

TABLE 24. RECTISOL® OFF-GAS COMPOSITION (SOURCE: CA-161)

Component	Mol %
CO_2	97.63
H_2S	0.75
Ethene (C_2H_4)	0.24
CO	0.07
H_2	0.43
CH_4	0.56
C_2H_6	0.32
Nitrogen (N_2) + argon (Ar)	-
TOTAL	100.00

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exhaust streams, and evaporation from scrubbing water at cooling towers. TABLE 24 gives the approximate composition of the off-gas from the Rectisol® solvent regeneration section in El Paso's Burnham coal gasification complex (CA-161). This illustrates that some hydrogen sulfide is still emitted to the atmosphere.

Nitrogen in the coal is responsible for the formation of compounds such as ammonia and hydrogen cyanide which are found in both the gaseous and liquid processing streams. Other gaseous compounds of interest are hydrogen chloride, hydrogen fluoride, trace elements that vaporize, and trace organics. The latter two groups of species will be discussed elsewhere. Ammonia, hydrogen cyanide, hydrogen chloride, and hydrogen fluoride should be removed by scrubbing. But they may be emitted by evaporation from cooling or scrubbing liquors in which they are dissolved or from fugitive emissions.

Water Effluents

Process wastewater treatment and subsequent handling represent one of the major problem areas in meeting environmental requirements. Environmental objectives are to be met by so-called "zero discharge" operations. This requires that the gasification facilities treat their process water for reuse or send it to lined solar evaporation ponds for disposal. Therefore, no liquid effluents should leave the boundary of the gasification plant.

Gasification processes are net consumers of water and, ideally, all streams could be recycled for use in the process. Effluent streams occur in practice because it is often technically or economically unfeasible to recycle all wastewaters consumptively, and to control all stream flows to yield the stoichiometric water requirement.

Principal pollutants in the effluent streams are hydrogen sulfide, ammonia, hydrogen cyanide, phenols, benzenes, and oils. In a proposed complex, 320 gallons per minute (gpm) of condensate from the gasifier is separated because of its high halogen, phenol and other organic compound concentrations and is sent to solar evaporation ponds. The high solids condensate is estimated to contain a high percentage of the chloride and fluoride in the coal (CA-161).

A good example of the condensate from a gasification process is given in TABLE 25 for the by-product water analysis from Synthane gasification. TABLE 26 gives an analysis of the trace elements in the water effluent for one type of coal in the Synthane process (FO-026).

Tars and oils are separated from wastewater by specific gravity; other organics such as phenols must be solvent extracted from the wastewater. TABLE 27 gives the analysis of tars obtained during Synthane gasification (FO-026).

Solid Wastes

Coal gasification processes produce large quantities of solid wastes. Most solid waste is due to the ash content of the coal and the sulfur removal processes.

Trace Organics

The coal gasifier output may contain all of the products commonly

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TABLE 25. BY-PRODUCT WATER ANALYSIS FROM SYNTHANE GASIFICATION OF VARIOUS COALS [mg/liter, EXCEPT pH] (SOURCE: FO-026)

	Coke Plant	Illinois No. 6 Coal	Wyoming Subbituminous Coal	Illinois Char	North Dakota Lignite	Western Kentucky Coal	Pittsburg Seam Coal
pH..............	9	8.6	8.7	7.9	9.2	8.9	9.3
Suspended Solids	50	600	140	24	64	55	23
Phenol..........	2,000	2,600	6,000	200	6,600	3,700	1,700
Chemical Oxygen Demand.........	7,000	15,000	43,000	1,700	38,000	19,000	19,000
Thiocyanate.....	1,000	152	23	21	22	200	188
Cyanide.........	100	0.6	0.23	0.1	0.1	0.5	0.6
Ammonia.........	5,000	[1]8,100	9,520	2,500	7,200	10,000	11,000
Chloride........	-	500	-	31	-	-	-
Carbonate.......	-	[2]6,000	-	-	-	-	-
Bicarbonate.....	-	[2]11,000	-	-	-	-	-
Total Sulfur....	-	[3]1,400	-	-	-	-	-

---

[1] 85 percent free NH_3.

[2] Not from same analysis.

[3] $S^{=}$ = 400 $S_4^{=}$ = 1,400
$SO_3^{=}$ = 300 S_2O_3 = 1,000

associated with pyrolysis, carbonization, and coking of coals in addition to oxygenated products associated with partial combustion. Several classes of compounds may be present. Various heavier organic compounds may be classified as tar (including phenols, cresols, pyridines, anilines, catechols), intermediate and high-boiling aromatics (naphthalenes), saturates, olefins, and thiophenes. Another group of organic compounds might be designated light oil and/or naphtha, including BTX, naphthalene, thiophene and condensable light hydrocarbons and disulfide carbon.

In a study of the effluent from an experimental coal gasification plant, certain organic components were extracted and tentatively identified. TABLE 28 lists these components. The particular distribution of organic compounds in raw gasifier gas will depend on the composition of the feed coal and the operating conditions of the gasifier.

At this time, conclusions as to the ultimate fate of trace organics in coal gasification plants must generally be estimates based on the composition of the coal, processing conditions, and data on actual emissions from processes such as boilers or coke ovens.

Processing conditions will affect trace organic effluents from a coal gasifier. The temperature and pressure in the gasifier and associated equipment could influence the fate of trace organics since the two major sources of trace organics are those originally present in the coal and released through

TABLE 26. TRACE ELEMENTS IN CONDENSATE FROM AN ILLINOIS NO. 6 COAL GASIFICATION TEST (SOURCE: FO-026)

	Sample No. 1	Sample No. 2	Average (by weight)
Parts per million (ppm):			
Calcium	4.4	3.6	4
Iron	2.6	2.9	3
Magnesium	1.5	1.8	2
Aluminum	0.8	0.7	0.8
Parts per billion (ppb):			
Selenium	401	323	360
Potassium	117	204	160
Barium	109	155	130
Phosphorus	82	92	90
Zinc	44	83	60
Manganese	36	38	40
Germanium	32	61	40
Arsenic	44	28	30
Nickel	23	34	30
Strontium	33	24	30
Tin	25	26	20
Copper	16	20	20
Columbium	7	5	6
Chromium	4	8	6
Vanadium	4	2	3
Cobalt	1	2	2

volatilization or leaching, and those formed by chemical reaction. For example, cracking of the hydrocarbons might occur in gasifiers operating at higher temperatures and pressures.

The results of the study of coke oven emissions indicate the presence of carcinogenic organic compounds in relatively heavy concentrations in the tar. Several classes of organic compounds are present in the tar from both a coke oven and a gasifier. Coke ovens also operate in the same temperature range as some gasification processes, but at a much lower pressure. Some of the hazardous hydrocarbons present in coke oven tar might also be present in gasifier tar since some similarities exist between the processes and contents of the tars.

Sampling and analyses of bench-scale Synthane gasifier effluents indicate trace organics might be present in the gasifier gas, tar, and by-product water streams. However, although these effluent streams are reported to be representative of those which will be obtained from a commercial operation, the applicability of this data to a commercial operation has not been proven. Some potentially hazardous trace organics will probably be emitted by a coal gasification process, but the ultimate fate of trace organics cannot be assessed at this time.

TABLE 27. MASS SPECTROMETRIC ANALYSES OF THE BENZENE-SOLUBLE TAR, VOLUME-PERCENT (SOURCE: FO-026)

Structural type (includes alkyl derivatives)	Run HP-1 No. 92, Illinois[1] No. 6 coal	Run HPL No. 94, lignite	Run HPM No. 111, Montana subbituminous coal	Run HP-118 No. 118[1], Pittsburgh seam coal
Benzenes	2.1	4.1	3.9	1.0
Indenes	[2]8.6	1.5	2.6	[2]6.1
Indans	1.9	3.5	4.9	2.1
Naphthalenes	11.6	19.0	15.3	16.5
Fluorenes	9.6	7.2	9.7	10.7
Acenaphthenes	13.5	12.0	11.1	15.8
3-ring aromatics	13.8	10.5	9.0	14.8
Phenylnaphthalenes	9.8	3.5	6.4	7.6
4-ring pericondensed	7.2	3.5	4.9	7.6
4-ring catacondensed	4.0	1.4	3.0	4.1
Phenols	2.8	13.7	5.5	3.0
Naphthols	(2)	9.7	9.6	(2)
Indanols	.9	1.7	1.5	.7
Acenaphthenols	-	2.5	4.6	2.0
Phenanthrols	2.7	-	.9	-
Dibenzofurans	6.3	5.2	5.6	4.7
Dibenzothiophenes	3.5	1.0	1.5	2.4
Benzonaphthothiophenes	1.7	-	-	-
B-heterocyclics[3]	(10.8)	(3.8)	(5.3)	(8.8)
Average molecular weight	212	173	230	202

[1] Spectra indicate traces of 5-ring aromatics.

[2] Includes any naphthol present (not resolved in these spectra).

[3] Data on N-free basis since isotope corrections were estimated.

Trace Elements

Although several potentially hazardous pollutants exist in coal only in trace amounts, gasification facilities will be processing 15 to 25 thousand tons of coal per day, which makes it necessary to investigate trace element species during gasification.

A gasification facility producing 15 to 20 trillion cubic feet of methane/year would require over one billion tons of coal/year. This conversion process could result in the production of the following trace elements in pounds/year: arsenic, 28 million; cadmium, 2 million; lead, 20 million; manganese, 108 million; mercury, 400 thousand; and nickel, 30 million (RH-008). These quantities could be emitted in concentrated areas.

Published data on the fate of trace elements in coal gasification systems

TABLE 28. COMPOUNDS TENTATIVELY IDENTIFIED IN WASTE EFFLUENTS OF COAL GASIFICATION PILOT PLANT (SOURCE: MC-130)

Restructured Gas Chromatograph Peak	Best Match	Second Best Match
1	Phenol	Phenol
2	o-Cresol	m-Cresol
3	m-Cresol	o-Cresol
4	2,5-Dimethylphenol	2,6-Dimethylphenol
5	3,4-Dimethylphenol	3,4-Dimethylphenol
6	2,4-Dimethylphenol	3,4-Dimethylphenol
7	α-Naphthol	1,2-Dihydroxy-1,2-Dihydronaphthalene

is limited. Attari (AT-042) has reported some data for the HYGAS pilot plant. The concentrations of 11 trace elements were measured in the solid streams entering and leaving each of the 3 stages of the HYGAS pilot plant.

Because the pilot plant was not operational during the period when the analytical work was performed, coal and char samples accumulated over several years of bench-scale research were used in the analysis. The emphasis of the project was placed on trace element analytical methods since sampling and operating criteria of the pilot plant were not discussed. The relative amounts of the trace elements found in the raw feed coal and the spent char from the gasifier are presented in TABLE 29. The loss values represent the removal of the trace elements from the solid streams. The data indicate substantial removal of mercury, selenium, arsenic, tellurium, lead, and cadmium from the coal during the gasification process. Most of the antimony, vanadium, nickel, and beryllium, and all of the chromium remained in the solid phase. Certain trace elements were definitely lost from the residue during gasification, but it was not known into which effluent stream the elements entered (AT-042).

As indicated earlier, trace elements were analyzed in the condensate from the Synthane gasifier. The data are presented in TABLE 26. Other trace elements analyses of the Synthane process performed on the gas and tars for hydrogen cyanide, arsenic, and mercury are presented in TABLE 30. The mercury was present in the gasifier gas but not in the final high-Btu gas product. The mercury and arsenic in the tars will probably enter the stack gas if the tar is burned (FO-026).

TABLE 29. LOSS OF TRACE ELEMENTS FROM SOLID PHASE DURING HYGAS GASIFICATION (SOURCE: AT-042)

Element	Percent Lost
Hg	96
Se	74
As	65
Te	64
Pb	63
Cd	62
Sb	33
V	30
Ni	24
Be	18
Cr	0

Note: Coal-feed was Pittsburgh No. 8 bituminous coal.

TABLE 30. TRACE COMPONENTS IN GAS AND TAR (SOURCE: FO-026)

	Gas (by volume)		Tar (by weight)	
	HCN, ppb	Mercury, ppm	Mercury, ppm	Arsenic, ppm
Illinois Char	5	-	-	-
Illinois No. 6 Coal	20	0.00001	0.003	0.7
Western Kentucky Coal	11	-	-	-
North Dakota Lignite	3	-	-	-
Wyoming Subbituminous Coal	2	-	-	-

The trace elements of primary concern in coal gasification are the following:

- antimony
- arsenic
- barium
- berryllium
- boron
- cadmium
- chlorine
- chromium
- copper
- fluorine
- lead
- mercury
- molybdenum
- nickel
- selenium
- sulfur
- tellurium
- uranium
- vanadium
- zinc

The chemical forms and ultimate fate of trace elements leaving the gasifier need to be known.

High-Btu Gasification

The data in this section summarize the impacts of a representative high-Btu coal gasification process producing 10^{12} Btu/day of gaseous product (RA-150).

The SNG-from-coal module emissions and impact are developed using two coal feeds, a western subbituminous coal and an Illinois coal. Where differences occur in the module due to the different coal feeds, both situations are explained. Otherwise, a general SNG-from-coal module is characterized. TABLE 31 summarizes the emissions and impact of SNG-from-coal plants which utilize Western and Illinois coal.

TABLE 31. ENVIRONMENTAL IMPACT OF SNG-FROM-COAL
(SOURCE: RA-150)
(BASIS: PRODUCTION OF 10^{12} Btu/DAY OF SNG)

Impact	Western Coal	Illinois Coal
Air (lb/hr)		
Particulates	727	944
SO_2	1,800	10,400
NO_x	7,110	7,770
CO	377	414
HC	115	126
NH_3	34.7	54.7
Water (lb/hr)		
Suspended Solids	0	0
Dissolved Solids	0	0
Organic Material	0	0
Thermal (Btu/hr)	Negligible	Negligible
Solid Wastes (tons/day	5,560	7,930
Coal Requirements (tons/day	83,000	66,900
Water Requirements (gal/day)	25×10^6	25×10^6

The nine processing steps in Radian's SNG-from-coal module are as following:

(1) coal pretreatment and thermal drying

(2) gasification

(3) cooling and solids removal

(4) catalytic shifting

(5) acid gas removal

(6) sulfur recovery

(7) catalytic methanation

(8) ammonia recovery

(9) product drying and compressing.

An auxiliary boiler, a steam superheater, a water treatment unit, oxygen plant and ammonia and sulfur storage facilities are required in SNG-coal processing. Specific processes are assumed for some of the processing units, although there are other alternatives available which could meet the process requirements. These alternatives should, however, exhibit environmentaly similar impacts.

Land Use

Land requirements for an SNG-from-coal plant may include areas for processing equipment, coal storage, solar evaporation ponds and solid waste disposal. It has been estimated that 165 acres are required for a plant capable of producing 236 x 10^9 Btu/day of SNG (AI-013). On a 10^{12} Btu/day basis, plant land requirements are 700 acres. The amount of land needed for evaporation ponds will depend upon the plant's geographic location and the pan evaporation rates of the region. Additional land may have to be used for disposal of solid wastes if these wastes cannot be returned to the mine for disposal. Based on an assumed solid waste density of 150 lb/ft^3, 30-foot high storage piles and a 30-year lifetime of the plant, 580 additional acres are required for a western coal feedstock and 820 additional acres are required for an Illinois coal feedstock (RA-150).

Air Emissions

Air emissions for the SNG-from-coal module come mainly from the secondary parts of the system. The auxiliary boiler, steam superheater, coal dryers and sulfur recovery system account for almost all of the emissions. None of the gasification train units should emit any pollutants directly to the air. There may, however, be fugitive emissions.

Water Emissions

Liquid wastes from an SNG-from-coal plant producing 275 x 10^9 Btu/day of SNG are emitted at the rate of 450,000 lb/hr or 900 gallons per minute (gpm) (EL-052). On a 10^{12} Btu/day basis approximately 1,640,000 lb/hr of liquid wastes are produced. These wastes contain high levels of dissolved solids, hazardous organic and trace inorganic compounds, and possible carcinogenic, organic species (RA-150).

Because of the presence of these hazardous compounds in a gasification plant's liquid wastes, these facilities are assumed to operate in a so-called "zero liquid discharge" manner. Therefore, provisions must be made to safely dispose of these wastes or incorporate them in a total water recycling plan. At the present time, the exact composition of these liquid wastes is not known. Thus, possible schemes for treating and recycling wastewater have not been devised.

Where possible, solar evaporation ponds will be used. Wastewater from primary water treatment, boiler blowdown, cooling tower blowdown and other contaminated streams are sent to these evaporation ponds. Since these streams contain high levels of dissolved solids and other pollutants such as phenols, the ponds are lined to prevent leakage of pollutants into underground water tables. In areas where evaporation ponds are not feasible, the liquid wastes must be treated and reused.

Solid Wastes

Solid wastes from an SNG-from-coal plant include ash, primary water treatment sludge and wastes from the ammonia recovery unit. Any sludges resulting from biological treatment of liquid streams can probably be used as fuel for the auxiliary boiler. The amounts of coal ash and slag produced are calculated from coal rates and compositions. The amount of particulates emitted to the air is subtracted from the total ash present in the coal feed. Ammonia still wastes are assumed to be 115 tons/day for a plant capable of producing 250 x 10^9 Btu/day of SNG (HI-083). This is then scaled to an output of 10^{12} Btu/day of SNG. The amount of primary water treatment sludge is calculated from (1) intake water requirements, (2) the assumption that 500 parts per million (ppm) of suspended solids are present in the make-up, and (3) all suspended solids are removed by chemical treatment.

The SNG-from-coal plant is assumed to be a mine-mouth operation and, hence, all solid wastes are expected to be disposed of as mine fill.

Thermal Discharges

Thermal discharges into water bodies are eliminated by utilizing wet cooling towers. If an adequate supply of water is not availble, air cooled condensors could replace cooling towers.

Low-Btu Gasification

The data in this section, developed in a previous study (RA-150), summarize the impacts of a representative low-Btu gasification process.

Low-Btu gasification module emissions and impacts are developed using two coal feeds, a western subbituminous coal and an Illinois coal. Air is assumed to be utilized in the gasifier as the source of oxygen for the low-Btu gasification module. TABLE 32 summarizes the emissions and impacts of low-Btu gasification plants which utilize western and Illinois coal.

Medium-Btu gasification module emissions are developed using only a western coal. In this analysis, the medium-Btu and low-Btu processes differ only in the manner in which oxygen is supplied to the gasifier. For medium-Btu gasification, 98%+ oxygen is the oxygen source. If not specifically mentioned in a section, medium-Btu gasification process features can be assumed to be those defined for the low-Btu gasification of western coal. TABLE 33 is a summary of the emissions and impacts of a medium-Btu gasification plant using western coal.

TABLE 32. ENVIRONMENTAL IMPACTS OF LOW-BTU COAL GASIFICATION
(Source: RA-150)
(Basis: Production of 10^{12} Btu/day of Low-Btu Fuel Gas)

Impacts	Western Coal	Illinois Coal
Air (lb/hr)		
Particulates	0.86	0.86
SO_2	580	2250
NO_x	1130	1130
CO	32.3	32.3
HC	32.6	32.5
NH_3	56.8	45.4
Water (lb/hr)		
Suspended Solids	0	0
Dissolved Solids	0	0
Organic Material	0	0
Thermal (Btu/hr)	negligible	negligible
Solid Wastes (tons/day)	5350	7320
Water Requirements (gal/day)	11×10^6	11×10^6
Coal Requirements (tons/days)	74,900	60,000

The processing units for Radian's low-Btu gasification module consist of the following:

(1) coal pretreater

(2) gasifier

(3) solids and liquids removal

(4) acid gas removal and sulfur recovery.

In addition, an auxiliary boiler, gas liquor treater, ammonia recovery unit and storage facilities are included.

TABLE 33. ENVIRONMENTAL IMPACTS OF MEDIUM-BTU GASIFICATION OF WESTERN COAL (Source: RA-150)
(Basis: Production of 10^{12} Btu/day of Medium-Btu Fuel Gas)

Air (lb/hr)	
Particulates	0.86
SO_2	568
NO_x	1130
CO	32.3
HC	32.6
NH_3	54.8
Water (lb/hr)	
Suspended Solids	0
Dissolved Solids	0
Organic Material	0
Thermal (Btu/hr)	negligible
Solid Wastes (tons/day)	5200
Water Requirements (gal/day)	13×10^6
Coal Requirements (tons/day)	74,400

Air Emissions

Air emissions from a low-Btu gasification system come from the sulfur recovery unit, the auxiliary boiler, storage facilities, and fugitive emissions.

Water Emissions

Water pollutants are considered to be nonexistent due to the use of solar evaporation ponds. Wastewater from primary water treatment, cooling tower blowdown and other contaminated streams are sent to these evaporation ponds. Since these blowdown streams contain high levels of dissolved solids and other pollutants, such as phenols, the ponds are lined to prevent leakage of pollutants into underground water.

Solid Wastes

Solid wastes from a low-Btu gasification plant consist of coal ash, primary water treatment sludge, ammonia-still wastes and limestone scrubber sludge.

If the gasification plant is a mine-mouth operation, all solid wastes would be disposed of as mine fill. If the gasification plant is not a mine-mouth operation, then provisions must be made to dispose of the solid wastes.

Thermal Discharges

Thermal discharges to water bodies are eliminated by utilizing wet cooling towers. If an adequate supply of water is not available, air cooled condensers could replace wet cooling towers.

Specific Gasification Processes

The previous discussions were generally applicable to all gasification processes. There is a limited amount of information on the environmental aspects of specific gasification processes. The Environmental Protection Agency has a series entitled "Evaluation of Pollution Control in Fossil Fuel Conversion Processes" which includes studies of several gasification processes (KA-142, JA-090, JA-121, MA-294, SH-149). Reports in this series define input and effluent streams and their compositions, examine pollution control facilities, suggest modifications in technology, and provide mass and energy balances. Some environmental aspects of various processes are discussed below.

Lurgi

The environmental aspects of SNG production by Lurgi coal gasification have been discussed in a report by EXXON Research Corporation (SH-149), in the environmental impact statements for the proposed El Paso and Wesco facilities, and in discussions by Berty (BE-218) and Cameron (CA-161).

The gas stream leaving the Lurgi gasifier contains coal dust, naphtha, phenol, ammonia, tar, tar oil, ash, char, and other constituents (SH-149).

Possible air emissions include nitrogen oxides, sulfur dioxide, hydrogen sulfide, other possible sulfur-containing species, particulates, carbon monoxide, hydrocarbons, ammonia, hydrogen fluoride, and trace elements. The nitrogen oxides result from fuel combustion processes in the superheater/incinerator, the power plant and associated equipment. The sulfur dioxide comes from the boiler, gas turbines, and other combustion equipment at the gasification plant. Other sulfur species will be released from the Rectisol® plant and by fugitive emissions. Large quantities of water vapor will also be emitted. Although not a pollutant, water can cause problems by fog formation or through reactions with other emissions (SH-149).

Control of water pollution is a major problem at Lurgi gasification plants. The plants are designed for zero water effluents so that no water is released beyond the plant boundaries. The major sources of water pollution are ammonia, phenols, organic by-products, hydrogen sulfide, hydrogen cyanide, hydrogen fluoride, carbon dioxide, fatty acids, biological oxygen demand, and suspended solids. Soluble phenols are removed by the Phenolsolvan® process. Inorganic compounds are removed by sour water treatment. Biological treatment is used to remove fatty acids, biological oxygen demand, and suspended solids. Even after extensive treatment, trace amounts of some species such as organic by-products may still remain. Traces of carcinogenic organic materials could enter the environment in the water spray from cooling towers (SH-149).

Due to a lack of direct information, the fate of trace elements in a Lurgi gasification plant is unknown. Most of the trace elements will probably end up in the ash, but the more volatile trace elements may be quenched and end up in the gas liquor system or may be adsorbed on particulate matter

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and emitted. Trace metals may be present as elements, inorganic compounds, or organic compounds. The range of trace elements that can be produced in a 2500-million stdft^3 Lurgi gasification plant using Navajo coal is shown in TABLE 34. In addition to trace elements, other trace pollutants may be heavy, condensed ring aromatic compounds that are either present in the coal or formed during the conversion process.

TABLE 34. RANGE OF TRACE ELEMENTS FOR 250 MILLION STDFT^3 GASIFICATION PLANT (SOURCE: SH-149)

Trace Elements	Minimum (lb/hour)	Maximum (lb/hour)
Antimony	0.65	2.6
Arsenic	0.22	6.5
Bismuth	0.00	0.43
Boron	130	324
Bromine	0.86	0.9
Cadmium	0.43	0.86
Fluorine	432	1690
Galium	1.1	17
Germanium	0.13	1.1
Lead	3.0	8.6
Mercury	0.43	0.76
Nickel	6.5	65
Selenium	0.17	0.45
Zinc	2.4	58
ROUNDED TOTAL	580	2,200

Koppers-Totzek

Compared to other coal conversion processes, the Koppers-Totzek coal gasification plant is very clean. Problems with objectionable and hazardous organic compounds are circumvented because the extreme gasifier temperatures are not conducive to the formation of organic compounds. Only minute quantities of organics are expected to form. Gasifier effluent streams will contain sulfur compounds (COS, H_2S, CS_2, SO_2), ammonia, cyanide, and trace elements. No gaseous streams are released to the atmosphere from the gasifier.

The major air effluent streams are the slag quench and gas-cooling system cooling towers, treated sulfur recovery tail gas and utility boiler flue gas. The cooling towers associated with the slag quench and gas cooling systems are expected to emit dissolved gases picked up from the gasifier product gas. These gases may include carbonyl sulfide (COS), H_2S, CS_2, SO_2, NH_3, and HCN. The treated tail gas from the sulfur recovery unit will contain 100 parts per million volts (ppmv) of sulfur species, which are predominantly

COS, and 10 ppmv H_2S. Utility boiler flue gas is expected to contain particulates, NO_2, and SO_2 at levels near the national standard. The flue gas will also contain some trace elements introduced with the coal. Studies have identified very small quantities of polynuclear compounds in the flue gas of coal-fired boilers.

In TABLE 35, the gas analyses at various processing stages indicate the possible contaminants and their concentrations (FA-024).

TABLE 35. GAS ANALYSES (EXPRESSED IN VOLUME PERCENT) IN KOPPERS-TOTZEK PLANT (SOURCE: FA-024)

Component	Gasifier Outlet	To Compression & Acid Gas Removal	Product Gas
CO	37.36	49.50	53.16
CO_2	7.13	9.42	9.44
CH_4	0.08	0.11	0.12
H_2	25.17	33.35	36.51
N_2	0.30	0.40	0.44
H_2S	0.23	0.30	3 ppmv
COS	178 ppmv	235 ppmv	1.5 ppmv
HCN	288 ppmv	300 ppmv	1 ppmv
NH_3	0.17	0.22	1 ppmv
H_2O	29.19	6.20	160 ppmv
Ar	0.32	0.42	0.46
SO_2	22 ppmv	15 ppmv	0.5 ppmv
NO	7 ppmv	7 ppmv	3 ppmv
Particulates (g/scf)	11.57	<0.002	<0.002

The most significant aqueous effluent stream is the ammonia cooler condensate containing approximately 70 weight percent water and 30 weight percent methanol. Water analyses of the various gas cooling and cleaning steps can be found in reference FA-024.

The gasifier fly ash and gasifier slag sludges are expected to contain the bulk of the trace elements. These sludges will also contain dissolved sulfur compounds, ammonia, and cyanides. Fly ash, slag, and waste limestone sludge from the utility boiler are expected to contain trace elements and polynuclear organics generated from coal combustion.

BI-GAS

The BI-GAS Process produces no appreciable amounts of tar, naphtha, or phenols (JA-121). The principal by-products are ammonia, sulfur and slag. Carbonyl sulfide, carbon disulfide, thiophene, and hydrogen sulfide must be removed from the product gas. For each 12,000 tons of coal gasified per day, 844 tons of slag will be produced (GR-109). The slag, the exact nature of which is unknown, poses a disposal problem. Ammonia which can be stripped by conventional means is the principal contaminant in the process water.

CO_2 Acceptor

The CO_2 Acceptor Process is for use on low-sulfur western coals. At least one-half of the sulfur release within this process occurs at a point different from that in any other coal gasification process. Coal ash and spent dolomite acceptor, which exit overhead from the regenerator vessel, carry bound sulfur. The calcium content of the lignite and the lime portion of the dolomite bind much of the sulfur as calcium sulfide. Before burial in the mine area, these spent materials must be stabilized by treating them with water and carbon dioxide to displace hydrogen sulfide and form calcium carbonate. The carbon dioxide can be from the carbon dioxide/hydrogen sulfide scrubbing system. Thus, both the gas streams which contain hydrogen sulfide can go to the sulfur recovery plant (FE-068).

Effluent from the sour water stripper will contain traces of phenols, tar, and naphthalene which must be removed. Small amounts of trace elements may also volatilize in the gasifier effluent (JA-090). The principal environmental problem with the CO_2 Acceptor Process is the disposal of spent dolomite.

Synthane

From an environmental standpoint, the Synthane Process is perhaps the most studied of all the gasification schemes. Environmental studies have been performed in conjunction with the engineering development (FO-026, FO-040, KA-142). Analyses of the tar, chars, gases, and water in the effluent streams are listed in TABLES 25, 26, 27, 28, and 30. These results are for bench-scale experiments. The prototype plant is now operating and initial results on the trace elements are available (FO-040). The Synthane Process produces a substantial quantity of char.

COAL LIQUEFACTION

As in coal gasification, one of the concerns of coal liquefaction is that, in the attempt to convert coal to a clean liquid fuel, sizeable environmental impacts are not transferred from conventional coal utilization facilities to liquefaction plants. Coal liquefaction facilities will process less coal than gasification plants but will still have the potential for a sizeable impact. Important considerations in determining the impacts of a coal liquefacation facility are the composition of the coal processed and the effects of operating conditions on the chemical formation of possible pollutant species.

The Ralph M. Parsons Company has defined some of the environmental factors in designing a 10,000 tons/day coal liquefaction plant (OH-006, PA-139). Such a plant would produce two low-sulfur fuels, some naphtha, and by-product sulfur. Figure 52 (OH-006) gives the overall material balance of the liquefaction plant and shows the waste streams.

Principal gas streams are from the oxygen plant, CO_2-removal unit, sulfur-removal unit and auxiliary equipment. Sulfur dioxide occurs in sulfur plant tail gas and in emissions from auxiliary combustion. Nitrogen oxides, carbon monoxide, and hydrocarbons are caused by incomplete combustion in utility systems. Carbon dioxide and small amounts of hydrogen sulfide are also emitted to the atmosphere. Approximately one billion cubic feet/day of various gas streams are exhausted to the atmosphere (OH-006).

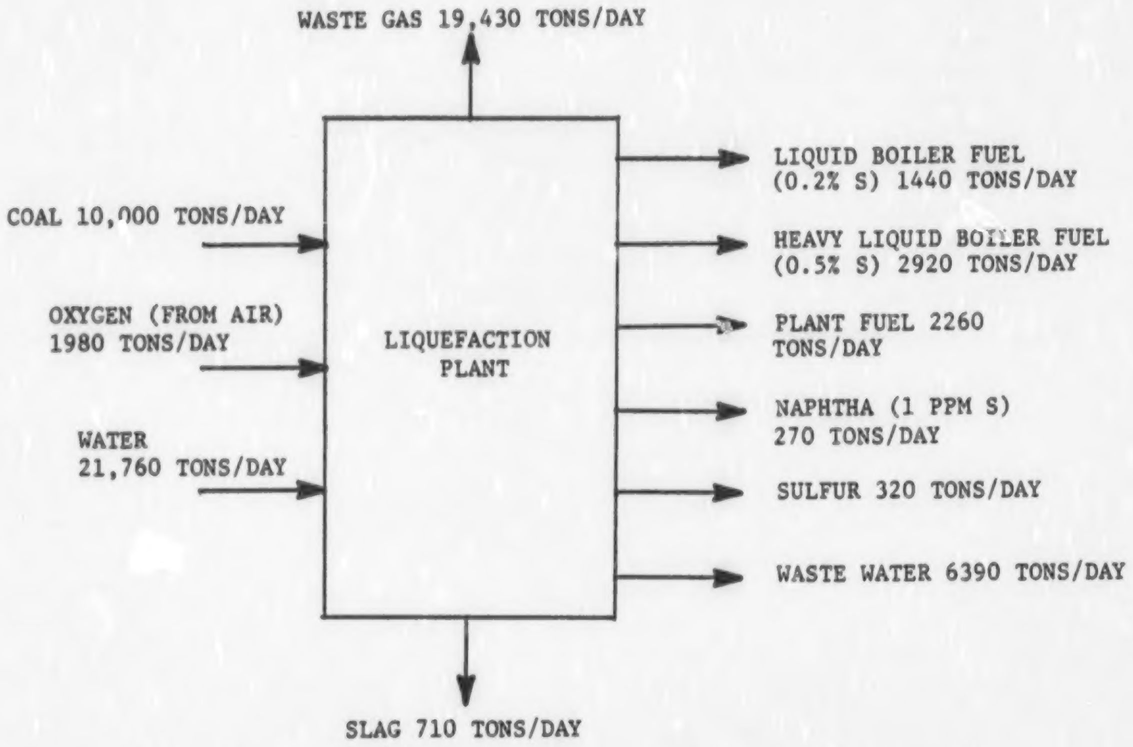
WASTE GAS 19,430 TONS/DAY
COAL 10,000 TONS/DAY
OXYGEN (FROM AIR) 1980 TONS/DAY
WATER 21,760 TONS/DAY
LIQUEFACTION PLANT
LIQUID BOILER FUEL (0.2% S) 1440 TONS/DAY
HEAVY LIQUID BOILER FUEL (0.5% S) 2920 TONS/DAY
PLANT FUEL 2260 TONS/DAY
NAPHTHA (1 PPM S) 270 TONS/DAY
SULFUR 320 TONS/DAY
WASTE WATER 6390 TONS/DAY
SLAG 710 TONS/DAY

Figure 52. Overall material balance for liquefaction plant.

About 1,060 gallons/ minute of wastewater are discharged from the liquefaction complex. Wastewater comes from cooling tower blowdown, sanitary wastewater, boiler blowdown, treated oily water, and stripped sour water (Figure 53, OH-006). Potential pollutants in the water streams include phenols, ammonia, acid oil, naphtha, suspended solids, and trace elements. Some liquefaction facilities will initially treat wastewater, send it to a holding pond for further treatment, and then discharge it from the complex. TABLE 36 summarizes the estimated wastewater treatment data and contaminants in the effluent stream leaving the complex (OH-006). Other liquefaction facilities, however, will operate on a so-called "zero discharge" basis and not have a liquid discharge stream leaving the complex boundaries (RA-150, KA-154). These plants will employ solar evaporation ponds to hold the liquid effluents. The selection of the method is very important in assessing the environmental impacts of a liquefaction plant.

TABLE 36. ESTIMATED WASTEWATER EFFLUENT CONCENTRATIONS FOR DEMONSTRATION PLANT

Constituents	Biological Influent lb/day	Biological Influent ppm	Biological Effluent lb/day	Biological Effluent ppm
Sulfide	1.48	0.12	0.06	0
Ammonia	24	1.88	1.45	0.11
Oil	72	5.63	8.64	0.68
TOC	60	4.69	-	-
BOD	538	42	134.5	10.5
Suspended Solids	660	51.6	165	12.9
Phenol	96	7.5	4.8	0.38
COD	1,920	150	576	45
Phosphate	145	11.3	1.45	0.11
pH	6-9	6-9	6-9	6-9
Chromate	91	7.1	91	7.1
Zinc	45	3.5	45	3.5
Coliform Organism		15/100 ml		15/100 ml

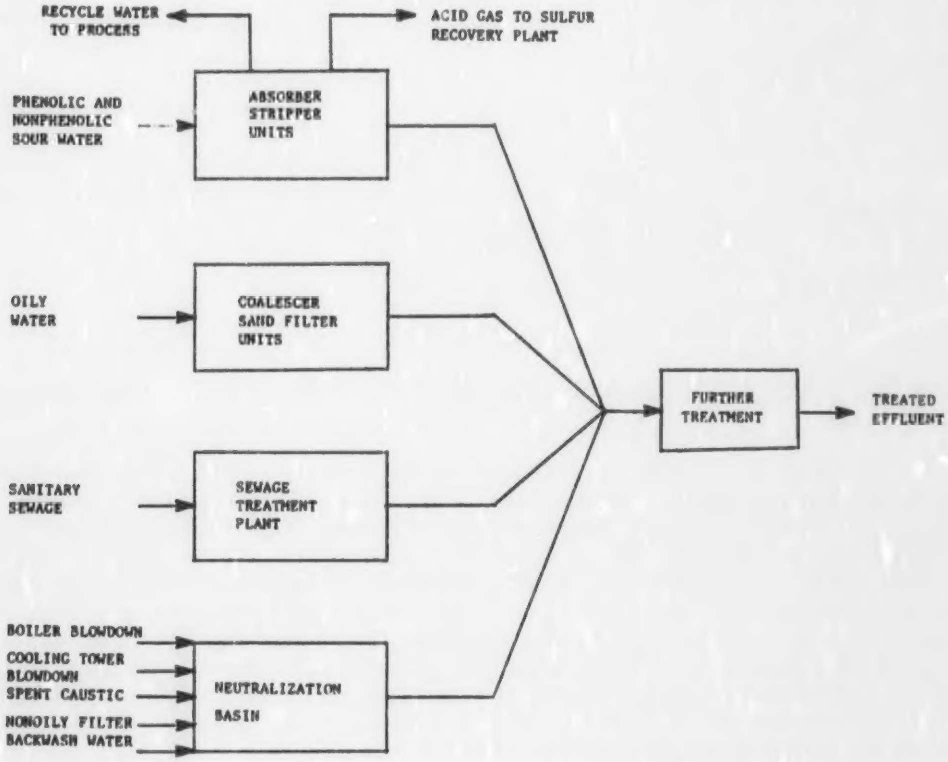
RECYCLE WATER TO PROCESS
ACID GAS TO SULFUR RECOVERY PLANT
PHENOLIC AND NONPHENOLIC SOUR WATER
ABSORBER STRIPPER UNITS
OILY WATER
COALESCER SAND FILTER UNITS
SANITARY SEWAGE
SEWAGE TREATMENT PLANT
FURTHER TREATMENT
TREATED EFFLUENT
BOILER BLOWDOWN
COOLING TOWER BLOWDOWN
SPENT CAUSTIC
NONOILY FILTER BACKWASH WATER
NEUTRALIZATION BASIN

Figure 53. Major wastewater streams in a coal liquefaction plant.

The production of solid wastes is shown in Figure 54.

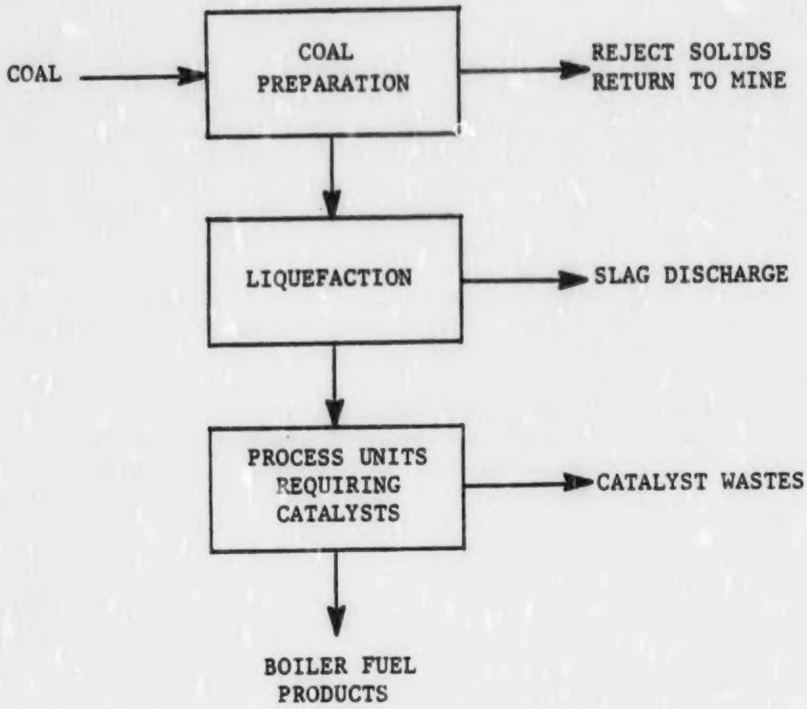
COAL
COAL PREPARATION
REJECT SOLIDS RETURN TO MINE
LIQUEFACTION
SLAG DISCHARGE
PROCESS UNITS REQUIRING CATALYSTS
CATALYST WASTES
BOILER FUEL PRODUCTS

Figure 54. Solid waste streams for a demonstration plant making clean boiler fuels from coal.

The possible environmental impacts identified in this report to this point have been very limited and idealized. Potential pollutants other than those previously mentioned may exist. The exact pollutants will be determined by the coal composition and the operating conditions of the liquefaction reactor. The fate of these species will be determined by the product processing steps, control and treatment facilities, and the likelihood of fugitive emissions. For example, liquefaction reactors operate completely in a closed system so that ideally there should be no stream discharge to the atmosphere, but because they operate at high pressures, leaks and fugitive emissions can cause serious pollution problems.

Potential pollutants that may arise in one or more effluent streams are sulfur oxides, reduced sulfur compounds, ammonia, hydrogen cyanide, phenols, carbon oxides, tars, oils, and trace elements. Carbonyl sulfide and carbon disulfide are more difficult to remove than hydrogen sulfide and may be emitted to the air (HI-080).

The fate of trace elements is very important in liquefaction processes. Their impacts may be important in effluent streams from the liquefaction plant and in the utilization of the liquefaction product. Information on the environmental relevance of trace elements in coal liquefaction is still very limited, but available data indicate the need for continued research in this important area.

The minor components, sulfur and nitrogen, and the trace element selenium have been used as examples for identifying the problems associated with determining the fate of trace elements in liquefaction processes (LO-090). Organically-bound selenium may leave the process in the liquid product or as hydrogen selenide in the gas phase. Hydrogen selenide can decompose to metallic selenium which has a high vapor pressure. Hydrogen selenide can also dissolve in aqueous streams and is a moderate reducing agent. Selenium may also be found in an inorganic ash phase as selenides, selenites, or selenates (LO-090). Therefore, a trace element may have many possible fates. The fate of trace elements in coal liquefaction will be determined by the interaction of coal constituents and processing conditions.

The importance of trace elements in coal liquefaction has been outlined in a study of the Solvent Refined Coal Process (SRC) (JA-096). The SRC product contains appreciable amounts of certain trace elements, especially titanium which may reach a concentration as high as 300 ppm. Although titanium is not a very toxic element, its high content in the product is both unusual and important and may suggest the formation of organometallic compounds. Vanadium, nickel, beryllium, cobalt, copper, and lead also are contained in significant amounts in the product. However, the importance and need for more research has been established for trace elements in liquefaction processes.

The next section will be devoted to the calculation of a liquefaction module.

Liquefaction Module

The module calculations discussed here are based on a coal liquefaction plant producing 10^{12} Btu/day of primary liquid fuels. For a coal liquefaction plant these primary fuels include naphtha, fuel oil, and residual oil. The thermal efficiency* selected for this module, 62.5%, is the efficiency given for the modified Solvent Refined Coal Process by Pittsburgh and Midway Mining Company (PA-139). This efficiency is chosen since the SRC Process appears to be under serious consideration for commercial operation, with a 50 ton per day (tpd) pilot plant under construction and the design of a 10,000 tpd demonstration plant completed. In addition, the demonstration plant designed by Ralph M. Parsons Company (PA-139) provides a good source for checking the heat and mass flows associated with a liquefaction process. Liquefaction modules are analyzed for a western coal with a heating value of 8,806 Btu/lb and an Illinois coal with a heating value of 10,820 Btu/lb. TABLES 37 and 38 summarize the emissions from the two liquefaction modules.

$$^{*}\text{Thermal Efficiency} = \frac{\text{Heating Value of Primary Fuels}}{\text{Heating Value of Coal Feed}} \times 100$$

TABLE 37. ENVIRONMENTAL IMPACTS OF COAL LIQUEFACTION MODULE FEED: WESTERN COAL

Air (lb/hr)	
Particulates	633
SO_2	1493
NO_x	8507.5
CO	340
HC	2607.6
Water (lb/hr)	
Suspended Solids	0
Dissolved Solids	0
Organic Material	0
Thermal (Btu/hr)	Negligible
Solid Wastes (tons/day)	5519
Land Use (acres)	3254
Water Requirements (gal/day)	33.3×10^6

Notes: (1) Modules based on 10^{12} Btu/day output of liquid fuel.
(2) Heating value of western coal is 8806 Btu/lb.

The processing facilities considered to be part of the liquefaction module are as follows:

- coal stockpiling facilities
- coal preparation facilities
- coal slurrying tank
- coal preheater and reactor
- flash system
- filtration system
- fractionation
- naphtha hydrotreater
- fuel oil hydrotreater
- char gasifier
- acid gas removal unit
- shift conversion unit
- methanation unit
- oxygen plant
- Claus plant
- tail gas treating unit
- ammonia separation facilities
- power generation unit
- steam generation boiler
- water treatment facilities
- product tankage

The major processing steps are coal dissolution, product fractionation, naphtha hydrotreating, fuel oil hydrotreating, char gasification, acid gas removal, shift conversion, methanation, oxygen plant, and sulfur recovery. The facilities and processing sequences are the same in both western and Illinois coal modules.

TABLE 38. SUMMARY OF ENVIRONMENTAL IMPACTS OF COAL LIQUEFACTION MODULE
FEED: ILLINOIS COAL (10,820 BTU/LB)
(BASIS: 10^{12} BTU/DAY OUTPUT LIQUID FUEL)

Air (lb/hr)	
Particulates	612
SO_2	1957.7
NO_x	8507.5
CO	340
HC	2607.6
Water (lb/hr)	
Suspended Solids	0
Dissolved Solids	0
Organic Material	0
Thermal (Btu/hr)	Negligible
Solid Wastes (tons/day)	8423
Land Use (acres)	3254
Water Requirements	33.3×10^6

Air Emissions

Air emissions from the module result from fuel combustion, coal preparation, sulfur recovery, ammonia storage, petroleum storage and miscellaneous hydrocarbon losses.

Fuel combustion emission sources are assumed to be the following:

liquefaction reactor preheater
product fractionator
fuel oil hydrotreater
naphtha hydrotreater
char gasifier
shift converter
power generation
steam generation.

Water Effluents

Water effluents are nonexistent since the module is assumed to operate with zero discharge (HI-083).

Thermal Emissions

Thermal discharge to water bodies is zero since no water is discharged from the module.

Solid Wastes

Solid wastes are determined from the amount of ash in the coal and solids in the make-up water. Radian assumed there are 500 ppm solids in the make-up water. Solid wastes resulting from silt in the make-up water is 70 tpd. Ash produced by the module is 5449 tpd for western coal and 8353 tpd for Illinois coal. Total solid wastes for the western coal module are 5519 tpd and wastes from the Illinois coal module are 8423 tpd.

OIL SHALE DEVELOPMENT

Oil shale development has the potential to cause a number of adverse environmental consequences. Research has been undertaken to determine what the possible adverse impacts are and what pollution control measures can be applied to prevent or minimize these effects. The most comprehensive study to date has been the Final Environmental Statement for the Prototype Oil Shale Leasing Program (US-093). Important elements of this work have been summarized in a paper discussing proposed legislation concerned with oil shale development (CO-229). This study assesses the technology, environmental impact, alternatives, and public and private reactions of the oil shale leasing program. Concerning the environment, it discusses land and water requirements, effects on air and water quality, and socioeconomic effects. The environmental impact statement did not discuss the fate and potential impact of inorganic trace elements and/or polyaromatic compounds. A summary of the environmental studies of the oil shale industry has been assembled by the Rocky Mountain Oil and Gas Association (RO-201).

Colony Development Corporation has prepared an environmental impact analysis for a proposed oil shale complex (CO-175), and the United States Bureau of Mines is preparing an environmental impact statement for this complex. Colony is also taking environmental baseline data and studying pollution control measures (HE-129).

The following sections will discuss the environmental aspects of oil shale mining, processing, and waste disposal. The mining and processing impacts of oil shale are interrelated because both steps are performed in conjunction with each other and share the waste disposal problem. Although spent shale is generated in the processing step, the environmental impacts of spent shale including disposal requirements, are generally enumerated along with those for mining. The major environmental impact of oil shale, the disposal of spent shale, greatly affects both land and water resources. Because of the size of this problem, waste disposal warrants a separate disucssion.

Oil Shale Extraction

Oil shale extraction in this discussion will consider the mining and crushing operations. Both underground and surface mining are considered.

Underground Mining

Water Requirements

Water requirements for underground mining are negligible. The primary requirement, dust suppression, is satisfied by using the water collected in the mined areas. Water used for dust suppression in the crushing operation is expected to amount to 3 to 5 percent of the total water used in an oil shale development (UN-025).

Water Effluents

The effects of underground mining on water pollution should normally be negligible. A major environmental aspect is the possibility of encountering large volumes of saline water during mining. Inadequate control of this water could pose significant problems including adverse effects on ground water conditions (HU-079). Improper disposal of the highly saline water could pollute stream water. Dewatering a mine may also depress the level of ground water tapped by wells.

Solid Wastes

Solid wastes produced during underground mining consist of overburden rock removed to reach the oil shale. Spent shale from the processing stage will be returned to the mining area along with the overburden. These aspects will be discussed later in the report.

Land Use and Disturbance

Due to the large quantity of solids involved in oil shale mining, one of the major problem areas is solid waste disposal and land requirements. The fixed land requirement for an underground mine is only about 10 acres of surface land; however, land must be available for disposal of both the overburden from the mine opening and the spent shale from the retort (assuming spent shale is disposed of at the mine site). With compacting, it is estimated that about 60 percent of the spent shale can be returned underground with the remaining 40 percent being disposed of on the surface (US-093).

The land requirement has been quantified using an underground mining module based on a raw shale production of 10^{12} Btu/day. The module is defined for a 30 gallon/ton grade of shale with a heating value of 3765 Btu/lb (RA-150). Land requirements for the module are determined from estimates for an underground mine supplying shale for a 50,000 bbl/day shale oil facility (US-093). An estimate of the land impact for an underground mining module producing 10^{12} Btu raw shale/day is as follows:

(1) mine development: 20 acres

(2) solid waste disposal assuming 60% return of processed shale underground: 51 acre/year

(3) crushing facilities: 40 acres.

Assuming a 30-year mine life, the total land impact is 1,590 acres (RA-150).

Air Emissions

Estimates of the air emissions are to be based upon the oil shale necessary to produce 50,000 bbl/day of shale oil and adjusted to 10^{12} Btu/day so that the estimate may be compared to other extraction procedures. The 50,000 bbl/day module is chosen because this is the commercial-size facility that has been chosen for most planning purposes; the 10^{12} Btu/day module is the most commonly used basis of comparison for energy modules.

The room and pillar mine module is based on a removal rate of 73,700 tons of oil shale per day. This is enough to produce 50,000 bbl/day of shale oil (US-093). The oil shale has an oil content of 30 gallon/ton of shale. This value is believed to be near the minimum allowable oil content to make oil shale processing economically feasible (US-093). A summary of the environmental impact is given in TABLE 39.

TABLE 39. SUMMARY OF ATMOSPHERIC EMISSIONS
OF OIL SHALE ROOM AND PILLAR MINING MODULE
(BASIS: 73,700 TON/DAY OF PROCESSABLE OIL SHALE)

Air Emissions	lb/day
Particulates	3,680
SO_2	10
NO_x	141
CO	86
Hydrocarbons	16

There are four possible sources of emissions from the room and pillar oil shale mine: (1) blasting and primary crushing in the mine, (2) secondary and tertiary crushing and screening operations, (3) vehicular emissions, and (4) miscellaneous fugitive dust emissions. Emissions from the specific sources are listed in TABLE 40.

The air emissions for underground mining have been converted to a module basis of 10^{12} Btu shale/day and listed in TABLE 13 for comparision with emissions from other energy extraction methods.

Surface Mining

Water Requirements

Water is required for particulate control and solid waste reclamation. The actual mining operation and the crushing operation require, respectively, about 2 percent and 3 to 5 percent of the total water used in oil shale development. Solid waste reclamation requires a much large amount.

TABLE 40. SPECIFIC SOURCE EMISSIONS (LB/DAY) FOR
OIL SHALE ROOM AND PILLAR MINING MODULE
(Basis: 73,700 ton/day of Processable Oil Shale)

Activity	Paritculates	SO_2	CO	Hydrocarbons	NO_x
Blasting & Primary Crushing	360	-	-	-	-
Secondary & Tertiary Crushing & Screening*	3,100	-	-	-	-
Vehicular Emissions	5.0	10	86	16	141
Miscellaneous Fugitive Dust**	220	-	-	-	-
TOTAL	3,685	10	86	16	141

* 99 percent controlled by either fabric filters or wet scrubbers
** 80 percent controlled by dust control techniques

Water Effluents

Water pollution is a more serious problem in surface mining than in underground mining because runoff can pollute streams. The effects of such pollution have been considered negligible (HI-083, UN-025), but commercial-scale control procedures have not been demonstrated. Water from reclamation sites may be highly saline and contain trace elements and trace organics. The impacts of accidental discharge are still largely unknown.

Solid Wastes

Solid wastes originating from surface mining consist of the overburden removed to expose the oil shale deposit. The amount of solid wastes depends on the depth of the overburden; a more shallow overburden produces less solid wastes. Spent shale from the retorting process is returned to the mine site and constitutes part of the solid wastes.

Land Use and Disturbance

Surface mining of oil shale has a high land impact since all of the spent shale and solid waste must be handled on the surface. The large quantity of solids involved in surface mining and the return of spent shale to the mine site create major problems in solid waste disposal. The land requirement for developing a surface mine is 30 to 85 acres/year. During the initial phases of the operation, permanent disposal of overburden is off-site. After the first few years, the overburden and spent shale may be returned to mined portions of the land.

The land requirement has been quantified using a surface mining module based on a raw shale output of 10^{12} Btu/day from the crushers. The module is defined for a 30 gallon/ton oil shale with a heating value of 3,765 Btu/lb with a 450-foot overburden (RA-150).

Land requirements for the surface mining module is determined from estimates for a surface mining operation with a 50,000 bbl/day shale oil facility (US-093). An estimate of the land impact for a surface mining module producing 10^{12} Btu raw shale/day is as follows:

(1) mine development: 5 acre/year

(2) permanent overburden disposal: 1,000 acres

(3) low-grade shale storage: 150 acres

(4) disposal of spent shale: 145 acre/year.

Assuming a 30-year mine life, the total land impact is 7,150 acres (RA-150).

Reclamation activities for surface-mined oil shale are difficult because of the great volume of waste solids and large expanse of land. Reclamation involves disposal in the proper terrain, water management and water pollution control, and revegetation. The water consumption is the primary environmental concern in reclamation of land associated with surface-mined oil shale.

Air Emissions

Estimates of the air emissions will be based on the oil shale necessary to produce 50,000 bbl/day of shale oil, and this will be adjusted to 10^{12} Btu/day so that it may be compared to other extraction procedures.

The shale oil surface mining module is based on a removal of oil shale equal to 73,700 tons per day. This is enough oil shale to produce 50,000 bbl/day of upgraded shale oil. The oil shale has an oil content of 30 gallon/ton of shale. A summary of the environmental impact is give in TABLE 41.

TABLE 41. SUMMARY OF ATMOSPHERIC EMISSIONS
FOR OIL SHALE SURFACE MINING MODULE
(BASIS: 73,700 TONS/DAY OF PROCESSABLE OIL SHALE)

Air Emissions	lb/day
Particulates	18,000
SO_2	178
NO_x	2,440
CO	1,490
Hydrocarbons	284

The surface mining oil shale module is assumed to be in steady-state operation. This means the mine has been opened and oil shale is being removed at a rate of 73,700 ton/day. The oil shale bed is assumed to be 40 feet thick with a density of 90 lbs/ft^3 (US-093). The overburden is assumed to be 450 feet with a density of 0.05 ton/ft^3 (HE-083). The overburden is also removed by trucks to a reclaiming site assumed to be one mile away.

There are four possible sources of air emissions from the oil shale production module: (1) excavation and blasting, (2) fugitive dust emissions from transporting the oil shale and overburden, (3) vehicle emissions from the combustion of diesel fuel, and (4) primary, secondary, and tertiary crushing and screening operations. Emissions from the various sources are listed in TABLE 42.

The air emissions for a 10^{12} Btu/day surface mining module are compared with the emissions from other extraction techniques in TABLE 13.

Oil Shale Processing

Shale oil upgrading will be considered in the discussions of both the surface and in-situ processes.

TABLE 42. SOURCE EMISSIONS (LB/DAY) FOR OIL SHALE SURFACE MINING MODULE
Basis: 73,700 ton/day of Processable Oil Shale)

	Particulates	SO_x	CO	Hydrocarbons	NO_x
Excavation & Blasting*	1,460	-	-	-	-
Transporting Fugitive Dust					
- Truck Loading & Unloading*	11,800	-	-	-	-
- Truck Hauling*	61	-	-	-	-
- Conveying	negligible	-	-	-	-
Vehicle Emissions	86	178	1,485	284	2,440
Primary Crushing*	1,470	-	-	-	-
Secondary & Tertiary Crushing**	3,100	-	-	-	-
ROUNDED TOTAL	18,000	178	1,490	284	2,440

* 80 percent dust control from fugitive dust control techniques
** 99 percent dust control from bag houses or wet scrubbers

Surface Processing

Environmental effects directly associated with oil shale processing result from retorted or burned shales, water that has been produced or used in processing, and gaseous emissions. The actual impacts will vary depending upon the oil shale handling methods, retort design, retort operating conditions, and upgrading facilities. The following discussion will consider an oil shale process based upon the TOSCO II process developed by the Oil Shale Corporation. This approach has been used in similar studies (HI-083, UN-025).

The module calculations are based on an oil shale processing plant producing 10^{12} Btu per calendar day of the primary liquid fuels, naphtha, distillate oil, and/or a residual oil. The thermal efficiency selected for the oil shale processing moduel is 66.7% (HI-083). This value is the efficiency given for the TOSCO II process which appears to be the most advanced process and the most likely to reach commercial operation. In addition, the environmental impact analysis for the TOSCO II plant at Parachute Creek, Colorado, provides a good source of information on emission sources and fuel requirements (CO-175). Using a 66.7% primary efficiency, a charge rate of approximately 199,100 tons/day of raw shale (3,765 Btu/lb) is determined. A summary of emissions from the oil shale plant is presented in TABLE 43.

TABLE 43. SUMMARY OF ENVIRONMENTAL IMPACTS OF SHALE OIL RETORTING AND UPGRADING MODULE (SOURCE: RA-150) (BASIS: 10^{12} Btu OUTPUT LIQUID FUEL)

Air (lb/hr)	
Particulates	454
SO_2	5320
NO_x	1970
CO	175
HC	2650
Water (lb/hr)	
Suspended Solids	0
Dissolved Solids	0
Organic material	0
Thermal (Btu/hr)	Negligible
Solid Wastes (tons/day)	164×10^3
Land Use (acres)	2000
Water Requirements (gal/day)	21.1×10^6

The main processing steps involved with the shale oil module are as follows:

(1) retorting

(2) gas recovery and treating

(3) sulfur recovery

(4) delayed coking

(5) hydrogen generation

(6) naphtha hydrotreating

(7) gas-oil hydrotreating

(8) ammonia separation unit.

The processing sequence with effluent streams is shown in Figure 55. In addition to these processing units, support facilities such as utility boilers and water treating facilities are also included.

Water Requirements

Water requirements for this module are based on TOSCO II estimates (CO-175). Water demands associated with the oil shale industry cannot be accurately defined due to the uncertainty of water requirements for revegetation. TOSCO II water demands range between 4,790 gallons per minute (gpm) and 5,600 gpm depending upon the amount of water allocated for revegetation. The module water requirement is calculated using the following TOSCO II demands as a basis:

Make-Up to Water Treatment	3,055 gpm
Make-Up to Pyrolysis Unit	820 gpm
Dust Control for Processed Shale	250 gpm
Water for Revegetation	700 gpm
	4,825 gpm

A module water requirement of 21.1×10^6 gallon/day is thus calculated (RA-150).

Lack of data concerning water for revegetation causes considerable discrepancies in information about the water demands of an oil shale industry. A summary of water usage estimates for a million-barrel-per-day oil shale industry is as follows (RA-150):

Cameron and Jones(1959)	130,000 acre-ft/yr
Denver Research Institute (1954)	145,000 acre-ft/yr
United States Department of Incerior(1973)	155,000 acre-ft/yr
Colony Development Operation (1974)	175,000 acre-ft/yr

Because of the increase in estimations, a figure of 200,000 to 250,000 acre-feet of water per year is used for a million-barrel-per-day oil shale industry (GA-107).

Land Use

Land requirement for the module is determined from information in the Final Environmental Statement for the Prototype Oil Shale Leasing Program (US-093). 320 acres is assumed necessary for a shale oil facility producing 50,000 bbl/day. This land requirement is for retorting, upgrading, and off-site facilities. The land requirement for the TOSCO II Parachute Creek plant for these facilities is 315 acres. This figure does not include land required for mining, transportation, and spent shale disposal.

An equivalent land impact of 320 acres is assumed due to land requirements for expansion, for water containment (evaporation ponds), and for greenbelt. A basis of 640 acres for a 50,000 bbl/day facility is thus estimated for the module. Land required for the 10^{12} Btu/day module is estimated to be 2,000 acres.

Water Effluents

Water effluents are considered nonexistent since the module is assumed to operate with zero discharge (HI-083). Although large quantities of water are used [with the exception of the Superior process (WE-164)] and large quantities of wastewater are generated, it is assumed that no process water will be discharged into the river systems. Wastewater from retorting will be treated and used for particulate control, to moisturize spent shale, and for reclamation activities.

Retorting oil shale produces water both from heating the shale and from burning the fuel when internal combustion is used for heating. Because the water has been in contact with shale oil, the water contains substantial amounts of organic material from the kerogen and inorganic ions from the minerals in the shale (HE-129). Therefore, it is very important to insure that process water is properly treated and controlled.

The treatment, control, and recycling of water in an oil shale complex has not yet been demonstrated on a commercial-size basis. The concept of zero discharge does not consider the possible contamination of ground water.

An important water environmental problem will be the prevention of a salinity increase in the Colorado River. Removal of 2.2×10^8 m^3 or 180,000 acre-feet per year of water from the upper rivers of the system is expected to increase the salinity at Hoover Dam by about 1.4 percent (HU-079). These estimates are based on the projected size of the oil shale industry in 1985 (HU-079).

Thermal

Thermal discharge to water bodies is zero since no water is discharged from the module.

Solid Wastes

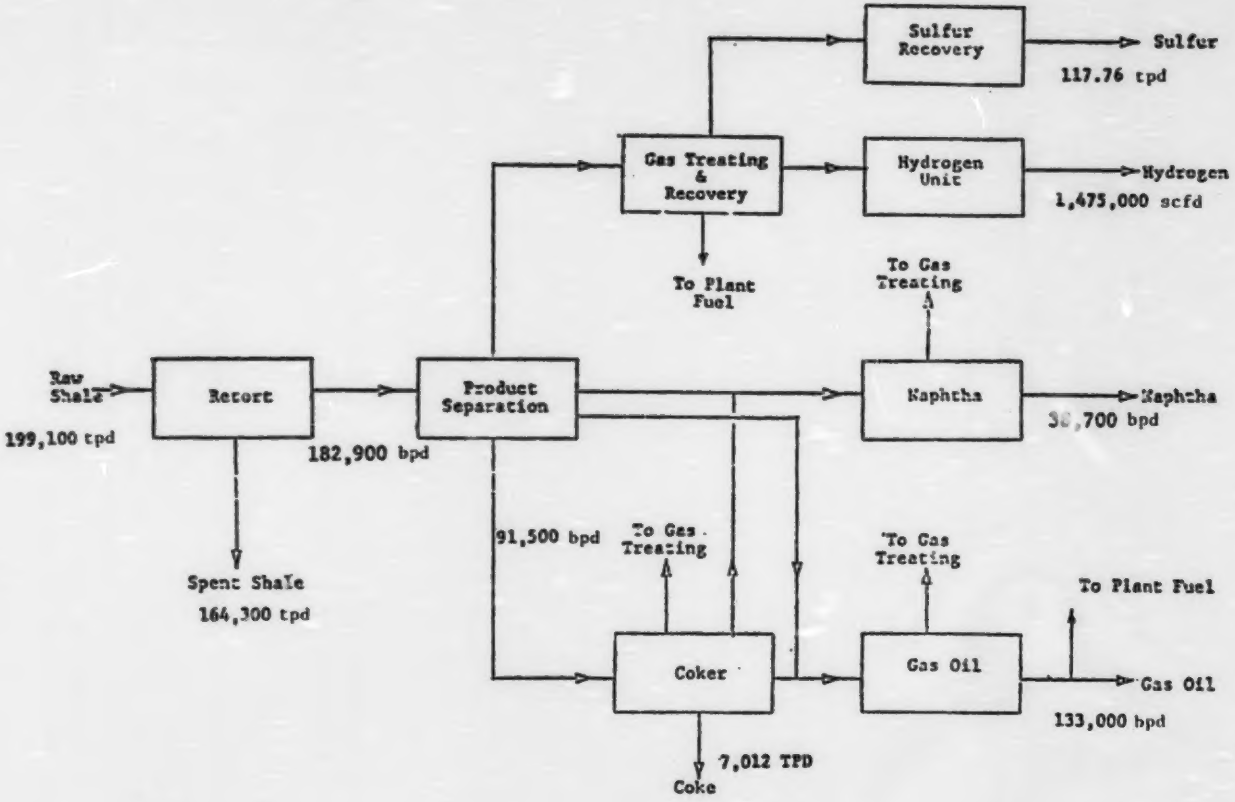
Sulfur Recovery
Sulfur
117.76 tpd
Gas Treating & Recovery
Hydrogen Unit
Hydrogen
1,475,000 scfd
To Plant Fuel
To Gas Treating
Raw Shale
199,100 tpd
Retort
182,900 bpd
Product Separation
Naphtha
Naphtha
38,700 bpd
Spent Shale
164,300 tpd
91,500 bpd
To Gas Treating
To Gas Treating
To Plant Fuel
Coker
Gas Oil
Gas Oil
133,000 bpd
7,012 TPD
Coke

Figure 55. Shale oil module.

Solid wastes are determined from the amount of spent shale in a typical shale oil process (US-093). This value of 60,000 tons per day of spent shale for a 72,700 tpd raw shale process is extrapolated to 164,300 tpd spent shale for the module. This waste is normally returned to the mine site for disposal.

Air Emissions

Air emissions result from solids handling, shale moisturizing, sulfur recovery, ammonia storage, fuel combustion, miscellaneous hydrocarbon emissions, and fugitive emissions from retorting.

A major source of emissions will be the combustion of low-Btu gas produced by retorting. Combustion of this gas for power generation produces sulfur oxides, nitrogen oxides, and carbon oxides.

Important sources of emissions are fugitive emissions from the retorting and upgrading facilities. In the retorting step, these fugitive emissions may contain sulfur compounds, ammonia, nitrogen oxides, trace elements, or miscellaneous hydrocarbons. The nature of these species depends on the operating conditions of the retort. Hydrocarbon emissions are the dominant fugitive emissions in the upgrading facilities. Fugitive emissions escape from sources such as valve stems, flanges, loading racks, equipment leaks, pump seals, sumps, and American Petroleum Institute (API) separators. These types of losses are discussed in Radian's refinery siting report (RA-119). Based on literature data, the miscellaneous hydrocarbon emissions amount to about 0.1 weight percent of refinery capacity for a new, well-designed, well-maintained refinery. This value of 0.1 weight percent is used to determine miscellaneous emissions from the shale oil upgrading facilities. Upgrading capacity is considered the feed to the distillation tower. Crude shale oil from the TOSCO II retort is approximately 20° American Petroleum Institute (US-093). The composition of these hydrocarbons can be expected to be a composite of all volatile intermediate and refined products. The emissions are assumed to occur at a height of 5 feet. A detailed air quality assessment has been made of the oil shale development program in the Piceance Creek Basin (EN-204).

Another consideration of the air emissions is the offensive and long-lasting odor produced by retorting oil shale.

In-Situ Processing

In-situ processing minimizes the solid wastes problem, but other environmental impacts are less well-defined because these processes are still being developed. Some possible environmental problems that may occur during in-situ oil shale processing are listed in TABLE 44. The different methods of in-situ retorting will produce different impacts on the environment. For example, the Occidental Company process produces a much larger solid waste problem than the United States Bureau of Mines process.

Water Requirements and Water Quality

Water requirements for in-situ processing have not been estimated. Water generated from the United States Bureau of Mines process requires primary treatment before further use or discharge. It must still be determined what effect leaching of the retorted shale and produced water will have on ground water.

Land Requirements

It is estimated that a United States Bureau of Mines facility producing 10^{12} Btu/day will require over 1,000 acres over a 30-year period. Requirements for the Occidental Company process are not known because solid waste disposal and reclamation techniques have not been established (UN-025). Subsidence of the land surface is a possibility if in-situ retorting is practiced on a commercial scale.

Solid Wastes

One of the advantages of in-situ processing is that it does not require the disposal of large quantities of retorted or burned shale. Some solids are produced during the drilling of the injection and production wells for the United States Bureau of Mines process. The Occidental Company process produces waste rock with a volume equal to 15 to 20 percent of the oil shale processed. Although this creates a sizeable disposal problem, the amount is less than 15 percent of the volume produced during surface processing.

Air Emissions

Estimates of the air emissions will be based on the production of 50,000 bbl/day of upgraded shale oil. These figures will then be adjusted so that the process can be compared to other extraction procedures. The United States Bureau of Mines process is the model for the module. The summary of the module air emissions are given in TABLE 45.

The four essential steps of in-situ retorting are the following:

(1) drilling of wells in front of the retorting zone

(2) fracturing of the oil shale

(3) injection of air and recirculation gas and formation of a temperature and pressure gradient within the oil shale

(4) recovery of the product.

A major source of air emissions from the in-situ retorting process is the flared low-Btu gas from the gas/oil separation and recovery plant. The expected composition of this gas before treating is listed in TABLE 46 (US-093).

The H_2S, assumed to be reduced to a 250 ppm concentration (EN-204), is combusted to SO_2 in the flare or incinerator. The CO in the gas is assumed to be reduced by 99 percent during incineration (EN-204). The particulate emissions factor from the flared gas is assumed equal to the emission factor for the firing of a fuel gas, 0.02 lb/1,000 scf (EN-071). The gas flow rate for a 50,000 bbl/day operation is approximately 1,485 x 10^9 scf/day (US-093).

TABLE 44. POSSIBLE ENVIRONMENTAL PROBLEMS FROM IN-SITU PRODUCTION OF SHALE OIL (SOURCE: HU-079)

Circulation of hot fluids	Loss of fluid to atmosphere Loss of fluid through fractures SO_2, NO_x, and particulates in flue gas Displacement of saline ground water Odorous off-gases
Circulation of solutions or solvents	Loss of volatiles to atmosphere Loss of solution to adjacent areas Contamination of aquifers
Underground combustion	SO_2, NO_x, and particulates in off-gas Odors in off-gas Loss of fluids to adjacent areas Contamination of aquifers
Nuclear chimney retorting	All problems common to underground combustion Blasting shockwaves detrimental to conventional mines and other installations Nuclear contamination of aquifers, air, and products

TABLE 45. SUMMARY OF ATMOSPHERIC EMISSIONS FOR IN-SITU SHALE OIL PRODUCTION MODULE (Basis: 50,000 bbl/day of Upgrade Shale Oil)

Air Emissions	lb/day
Particulates	29,700
SO_2	59,500
NO_x	12,400
CO	2,570
Hydrocarbons	14,500

The hydrocarbon emission factor for the flared low-Btu gas is assumed to be equal to the hydrocarbons resulting from combustion of an equivalent amount (heating value) of natural gas. This value is calculated by multiplying the hydrocarbon emission factor for natural gas by the ratio of the heating value of the low-Btu gas to that of a fuel gas (EN-071). This calculated emission factor is 0.0008 lb/1,000 scf. The nitrogen oxide emissions are estimated at 12,400 lb/day (EN-204).

TABLE 46. CHARACTERISTICS OF GASES FROM IN-SITU RETORTING[1] (SOURCE: US-093)

Component	Concentration/Volume-Percent
Nitrogen	73.7
Oxygen	3.4
Propane	0.2
Carbon Dioxide	21.4
Carbon Monoxide	0.1
Hydrogen Sulfide	0.1
Butanes	0.1
Methane	0.5
Ethane	0.5

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[1] Heating value approximately 30 Btu/scf
Yield from operation at level of 50,000 barrels per day upgraded (bbl/day)
Shale oil approximately 1,458 x 10^6 standard cubic feet per day (scf/day)

Miscellaneous fugitive gas emissions at the wellhead are estimated at 0.22 volume percent of the fuel gas. This emission factor comes from a Battelle report for miscellaneous gas losses occurring at gas wells (BA-230). Due to the large gas flow rates, fugitive gas emissions will be substantial. Fugitive dust emissions are estimated at 5.5 lb/day (EN-204).

TABLE 13 shows the comparison of in-situ air emissions with the emissions from other extraction modules based on 10^{12} Btu/day.

Solid Waste Disposal

A major problem associated with oil shale development involves solid wastes, i.e., the handling and ultimate disposal of spent shale. This problem significantly affects both land and water resources. Since a typical shale deposit contains 30 gallons of oil per ton, approximately 80-90 weight percent of the extracted shale must be disposed as spent shale. A 50,000 bbl/day shale oil facility would require about 73,000 tons/day of 30 gallons/ton oil shale and would produce over 60,000 tons of spent shale. Moreover, this waste shale occupies a volume about 40 percent greater than the original shale; even with maximum compaction, the shale increases in size by about 12 volume percent during processing (US-093). The handling and disposal of such large weights and volumes of spent shale presents a formidable task.

Most oil shale development plans call for the spent shale from the retort to be disposed at the mine site. An advantage of underground extraction over surface mining is that the spent shale may, to some extent, be disposed underground. About 60% of the processed shale may be backfilled in an underground mine, thus substantially reducing the surface impact. The exact amount of backfill depends on the type of spent shale, degree of compaction, moisture content, and mine volume used. The portion of the spent shale that cannot be placed underground must undergo surface disposal and reclamation. When surface mining is performed, overburden as well as processed shale must be disposed on the surface. Initially, overburden and spent shale are hauled to containment areas; when mined-out areas of the pit become available, backfilling can begin. Since the solid waste cannot be placed underground, the land impact associated with surface mining is higher than room-and-pillar mining.

Surface disposal of solid waste may be achieved by either containment (box canyons) or reclamation. Land reclamation and revegetation are desirable for reducing the land impact of the shale oil industry; however, procedures required to properly restore and revegetate the land have not been adequately defined. Total cost, time, and water requirements have not been accurately established.

The texture of the spent shale is determined by the retorting conditions and must be considered in establishing disposal techniques. Spent shale from a Gas Combustion Company retort is pebbly, but TOSCO II processed shale is powdery (UN-025). Once the shale has been retorted, the organic binding is destroyed and the rock is easily crushed. Soluble minerals may then be exposed and leached (HU-079).

The disposal of spent shale can significantly affect both water use and water quality. Processed shale disposal accounts for 40 percent of the total water requrements at the Colony facility (HE-129). Methods for preventing spent shale wastes from contaminating water supplies have been devised, but their practicality has not been demonstrated on a large scale. Materials that may be leached from shale disposal sites must be contained and prevented from entering the natural water systems. Without revegetation, intense, short-period rains could leach soluble compounds from the spent shale; benzo-a-pyrenes have been claimed to be present in the leachate from such sites. Leachate from disposal sites may increase the salinity, sediment, dissolved solids, and heavy metals in natural waters. The work of J. C. Ward (WA-103) on the water pollution potential of spent oil shale residues has been summarized (HU-079) and is shown in TABLE 47.

Both trace inorganics and organics are of increasing concern in pollution. The potential impact of inorganic trace elements in spent shale has not been adequately established. Work is in progress to determine the impact of polynuclear organic compounds present in carbonaceous shale ash (SC-239).

The composition of the spent shale depends on the type of retorting process and the retorting conditions. If high temperatures such as 1800° F as in the Union Oil Company process are used, decomposition of the carbonates occurs, and the spent shale is almost completely free of organic carbon. However, trace elements and soluble salts may still be present. Retorting at lower temperatures such as 900°-1000° F causes little mineral decomposition and yields a spent shale containing residual organic carbon (SC-239). Intermediate temperatures produce less organic carbon content. TOSCO II retorting results in the processed shale being coated with a thin carbon film (HE-129). These carbonaceous spent shales may contain polynuclear aromatic hydrocarbons, aza-azarines, and other high molecular weight organic compounds.

Polyaromatic hydrocarbons and aza-azarines have been identified in benzene soluble fractions extracted from carbonaceous oil shale. These fractions contain compounds with experimentally demonstrated carcinogenic effects. TABLE 48 lists some of the compounds identified in carbonaceous spent shale (SC-239).

Preliminary data indicate that a large number of polycyclic aromatic compounds can be leached from the carbonaceous shale residue and migrate with the saline water. This water has a polyaromatic hydrocarbon content which may be at least 3 to 4 order of magnitudes higher than natural ground water or surface water (SC-239). Although the presence of possible carcinogenic compounds has been established, the extent of this problem has not been determined, and research in this area is continuing.

POTENTIAL IMPACTS OF EMISSIONS

The coal conversion and oil shale processes discussed in this report are largely untried under conditions approximating commercial application. Consequently, although a number of potential pollutants have been identified which may be expected as by-products of the processes, it is impossible at this point to predict in what combinations and in what form they will come into contact with living organisms. In the following sections, the ecological relationships of each of fifteen major pollutants or types of pollutants will be discussed, as much as possible in terms of the pathways by which organisms, including man, may be exposed to them.

Exposure Pathways

The method by which contaminants may enter the biosphere will depend very much on the design and location of individual plants. The dispersal of airborne contaminants depends on terrain and synoptic air flow patterns, and their impact upon pre-existing ambient conditions. The method chosen for disposing process wastewater and solid wastes will determine the likelihood and probable means of environmental contamination. In view of the national goal of zero pollution discharge by 1985, it is likely that process-waste streams, including condensate from the conversion process, slurried ash or chars, and cooling water or boiler blowdown, will be impounded at the site. Contaminants may leave these ponds and enter the environment via overflow during periods of excessive runoff or flash flooding, or through a broken or imperfect seal. Many plants are likely to be built adjacent to a strip

TABLE 47. SUMMARY OF POTENTIAL WATER POLLUTION PROBLEMS CAUSED BY SPENT OIL SHALE RESIDUES

1. Leaching tests show a definite potential for high concentrations of Na^+, Ca^{++}, Mg^{++}, and $SO_4^=$ in the runoff from spent oil shale. With proper compaction, the piles become essentially impermeable to rainfall, but snowfall eliminates the compaction in the top 20 to 40 cm and the top half meter of the residue becomes permeable to water.

2. Soluble salts are leached readily from spent shale columns.

3. Effluent concentrations from spent shale columns may be predicted by equilibrium relationships between water and soluble and exchangeable ions in soils.

4. Sediment in runoff water from spent oil shale residue will be detrimental to water quality unless removed by settling.

5. Sediment in the runoff water may be settled by the addition of small amounts of aluminum sulfate and/or by long periods of quiescent detention.

6. The dissolved solids concentration in snowmelt water is increased significantly by contact with oil shale residue, but not as much as in runoff from rainfall.

7. The long contact with snowmelt results in water percolation into a a bed of oil shale residue and subsequent saturation.

8. Saturation eliminates compaction of oil shale residue.

9. Weathering of oil shale residue increases the likelihood of percolation.

10. Percolation caused by snowmelt may result in creep and slides.

11. Water percolating through oil shale residue is very high in total dissolved solids.

12. Both the composition and concentration of dissolved solids in snowmelt runoff water from oil shale residue change with the cumulative volume of runoff.

13. Precipitation in the form of snow will not all appear in runoff.

14. Saturation of the oil shale retorting residue is not required for percolation by snowmelt.

TABLE 48. POM* COMPOUNDS IDENTIFIED IN BENZENE EXTRACT OF CARBONACEOUS SHALE COKE FROM GREEN RIVER OIL SHALE (SOURCE: SC-239)

Name of Compound	Potential Carcinogenicity
Phenanthrene	--
Fluoranthene	--
Pyrene	--
Ananthrene (dibenzo [cdjk] pyrene)	--
Benz[a]anthracene (1,2-Benzanthracene)	+
Benzo[a]pyrene	+++
7,12 - dimenthyl[a]anthracene	++++
Perylene	--
Acridine	--
Dibenz[a,j]acridine (1,2-7,8-dibenzacridine)	++
Phenanthridine	unknown
Carbazole	--

---

*POM - polynuclear organic matter

coal mine. In these cases, solid wastes, including precipitated solids from evaporation ponds, can be disposed of in mine pits before regrading and reclamation. Since many of the western coals are either themselves aquifers or lie above or below water-bearing strata, the regraded spoils of a reclaimed strip mine, with their improved permeability, may act as a localized zone of ground-water recharge. Soluble materials disposed in the mine can enter the aquifer and reappear in springs or surface streams. Since in the Western states a large proportion of the base flow of many streams comes from springs, aquatic ecosystems may be affected by wastes even if no surface discharge occurs.

The design of the individual plant, its pollution control strategies and its geohydrologic setting will influence the extent and occurrence of pollution pathways. In some cases, proper design and careful site selection may render all types of contamination of surface and ground water insignificant. In others, there may be a possibility of measurable pollution.

An example of a reaction which might occur under the proper conditions is the precipitation of metals as sulfides formed in the presence of H_2S. At the same time, the highly toxic gas arsine may be formed wherever nascent hydrogen comes into contact with a solution containing arsenic. Chlorine mixes readily with phenols, forming toxic and very stable compounds. Microbial oxidation of organics of all kinds will be influenced strongly by the dissolved oxygen content of the impounded waste; the incorporation of oxygen content is a crucial step in the breakdown of many organic molecules.

Large impoundments of water have a tendency to attract wildlife; the number and types of which may be expected to vary greatly with the ecosystem, the time of year, the species of wildlife present and the composition of the water itself. Thus, the likelihood of direct exposure of wildlife to impounded effluents cannot be generally specified. The greatest probability of direct wildlife contact would probably occur in ponds containing relatively low concentrations of solutes. Such ponds would be far more likely to be visited by terrestrial wildlife than would ponds containing highly concentrated solutions, although waterfowl may continue to land even on relatively sterile waters.

This brief, qualitative discussion provides an idea of the major alternative routes by which the effluents characteristic of coal conversion or oil shale plants may enter the environment, as well as demonstrating their sensitivity to site, process and design. The large degree of uncertainty involved in exposure pathways places limitations on the conclusions which may legitimately be drawn from the subsequent paragraphs.

SO_2 and Particulates: New Perspectives

Data concerning the direct toxicity of SO_2 to plants, animals, and humans abound, and Federal ambient air quality standards have been set to fall conservatively below the level at which adverse effects begin to be observed. Recently, attention has been focused on the products formed by SO_2 in the atmosphere. Evidence that these products may be more significant both biologically and economically than SO_2 itself is beginning to accumulate.

The natural sulfur cycle includes a number of transformations, both inorganically and biologically mediated. An understanding of the fundamental features of this cycle will provide a sound basis for determining at which points it will be desirable to monitor sulfur, and for interpreting the results of these measurements and others already made.

Sulfur dioxide enters the atmosphere mainly from the decay of organic matter, releasing H_2S which is oxidized to SO_2, from volcanoes, or from the combustion of fossil fuels. Sulfur dioxide in the air is slowly oxidized to SO_3, which then reacts rapidly with water to form H_2SO_4 or with ammonia or metallic oxides to form a variety of sulfate compounds and particulate sulfates (EN-292, WE-191). Although field or laboratory data validating these reaction pathways are generally lacking, it is thought that most sulfates have an atmospheric residence time of 1 to 7 days (WO-063).

Sulfates and sulfuric acid regularly fall as rain from the atmosphere, entering the pool of sulfate in sediments and soils. Sulfur dioxide is absorbed directly by plants in which, after oxidation to sulfate, the SO_2 can supply part of a plant's sulfur requirements. From the plant, sulfur may pass in turn into the soil through root exudates, leaf leachate or decomposition of litter. The soil sulfate pool is represented in the cycle as the central wheel of oxidation and reduction reactions. These reactions are generally mediated by specialized microorganisms, drawing on sulfur in the form of reduced iron sulfides in deep sediments. A connection to the phosphorous cycle exists through these compounds; when iron sulfides are formed, phosphorous in sediments is converted from an insoluble to a soluble form (OD-011).

From the point of biological interactions, the critical points in this cycle occur principally at the conversion of SO_2 to sulfate, at the transfer of sulfates of H_2SO_4 from the atmosphere to land, and with the reactions of these products with soils and living vegetation. Except for extreme cases, the effects of sulfur added by man to the cycle may be thought of as being more adverse in the atmospheric phase and more beneficial in the soil/sediment phase.

Sulfates formed in the atmosphere differ greatly in size and chemical composition, and their direct effect upon human health, in the aggregate, is not completely understood. West (WE-191) reviewed the subject of sulfur and selenium compounds and commented that the response of man to particulate sulfates is "not traumatic" and that the sulfate species probably represent little risk to human health. Amdur and Corn (AM-148), however, showed zinc ammonium sulfate was perhaps 20 times as effective in increasing flow resistance in the lung as equivalent amounts of SO_2 used in other experiments. Frank et al. (FR-161) have also shown particulate sulfate to be a stronger irritant that SO_2 for guinea pigs. Baruch (BA-369) has recently reviewed the literature on atmospheric sulfates and concluded that there is reason to be concerned not only about sulfates in general, but also about the individual species present in the air, citing Uron, et al. (UR-016) and Butcher and Charison (BU-084).

Acid sulfate, sulfuric acid and SO_2 dissolved in aerosols presently appear to be the best documented sulfate pollutants with respect to health effects. All three act as irritants and can produce various increases in resistance to lung flow, an irritation apparently related to acidity.

Very little direct information on particulate sulfate is available. Concern over sulfates themselves is largely based on negative or circumstantial evidence. For example, mortality statistics in New York City over the period 1969-1972 showed little change, although SO_2 levels in the air decreased by 60% during the same period (SC-278). A long-term study of the effects of typical urban concentrations of SO_2 on cynomolgus monkeys and guinea pigs, particularly sensitive laboratory animals, indicated no detrimental effects (HA-370). This same series of studies, however, indicated a much greater sensitivity to sulfuric acid mist. This kind of observation has led investigators to suggest that SO_2 may be an indicator of air pollution, but that suspended acid sulfates constitute the actual damaging species.

Some evidence has begun to accumulate which suggests that the toxic effects of sulfate are related synergistically to fine particulate loading in the air. Although not conclusively demonstrated, this hypothesis is supported by both laboratory and epidemiological data. Studies undertaken by the EPA's Community Health and Environmental System (CHESS) have shown a relationship between asthma attacks in New York city and suspended particulates and suspended sulfates when minimum temperatures were below 30°-50° F. No relationship to SO_2 was observed. Morbidity excesses appeared when daily sulfate levels reached 7.3 $\mu g/m^3$ and minimum temperatures fell below 50° F (EN-292). Sodium chloride (NaCl) aerosols mixed with SO_2 has a synergistic effect on the lungs of guinea pigs (AM-147). Solution of SO_2 gas by deliquescent aerosols, which subsequently exhibit reduced pH, has been suggested as a significant pathway by which irritant acid sulfates may be formed and enter the lung (AM-147, FR-161, MC-113). Atmospheric chemistry studies (WR-009) indicate that the presence of manganese, vanadium or iron salts in the air will promote the conversion of SO_2 to sulfuric acid. In addition, some circumstantial evidence exists relating SO_2 and general levels of particulates in the air to chronic bronchitis and respiratory disease (CO-322, CH-261, FR-162, SH-220).

The implications of this evidence for future areas of concern in environmental monitoring strongly show the need for direct measurement of respirable particles (less than 5μ), especially aerosols, as well as of suspended sulfates. Baruch (BA-369) concludes that because of the possible interaction between fine particulates and sulfates which permit them to enter the lung, often with enhanced acidity, hazards to human health and welfare can occur when existing emissions and ambient air quality standards are met. Since standards do not presently take into account particle size, further quantitative study is definitely needed in this field.

In addition to the health effects of sulfates, some very strong correlations have been made between the pH of rainfall and reductions in the productivity of forest vegetation and increasing acidity in lakes leading to fish kills (LI-087, NI-057, WH-062). At a recent International Symposium on Acid Precipitation (Columbus, Ohio in May 1975) the most prevalent opinion was that sulfur and nitrogen oxides from industrial areas may cause acid rainfall, and that the widespread dispersal of these acid-forming species in the atmosphere extends their effects far from the original source. In the present context, however, it should be pointed out that, in general, documented cases of damaging acid rainfall have occurred downwind of large industrial complexes rather than individual plants (with the exception of certain smelting operations with an extremely high SO_2 output). While there exists a possibility that large industrial complexes may develop near some coal conversion facilities, there is no reason to conclude that harmful decreases in the pH of rainfall could be produced by any one isolated facility independent of other sources. Although monitoring the pH of rainfall around and especially downwind of a conversion complex would be useful in documenting the validity of this supposition, and probably should be undertaken as a means of expanding our understanding of the cause of acid rains, it probably will not be considered a critical monitoring task.

Neutral and alkaline soils apparently absorb SO_2 rapidly (AG-015, TE-142). Acid soils, however, absorb only small amounts. Absorption of SO_2 increases the acidity of soils in industrial regions (BO-163). Direct soil absorption of SO_2, as opposed to contribution by plants, probably assumes more significance in areas with sparse vegetation or in winter. Up to a point, sulfates entering the soil have a beneficial effect by increasing the amount of sulfur available to plants. In excessive quantities, however, changes in soil pH induced by sulfates in the soil can result in leaching of soil nutrients. The likelihood of soil leaching developing around a properly controlled single coal-conversion plant seems, like the possibility of acid rain, to be very small based on current understanding of the problem. Consequently, monitoring of soil pH may be considered more valuable in expanding our knowledge than controlling anticipated pollution problems.

Non-Criteria Air Pollutants

In addition to sulfur dioxide, nitrogen oxides and particulates, coal conversion and oil shale processes are likely to emit significant amounts of ammonia, principally from storage and loading of by-product ammonia, as well as small quantiies of hydrogen sulfide (H_2S) and hydrogen cyanide (HCN) encountered as minor fugitive losses largely within the plant and near the ground.

All three of these compounds are readily absorbed by soil (BU-069, KA-194), and ammonia is strongly absorbed by plants (HI-132). Both ammonia and hydrogen sulfide are part of naturally-occurring material cycles, so that their presence in very slightly increased quantities need not be considered as contamination.

Fugitive H_2S and HCN emissions constitute an almost exclusively in-plant problem which is unlikely to affect the surrounding environment. Quantities of ammonia emitted, however, may be on the order of 30 to 35 pounds per hour for a complex producing 1,000 million cubic feet per day (MMcfd) of SNG; with this much ammonia, it is possible that under certain circumstances vapor could escape beyond the plant boundaries. Unlike H_2S, ammonia is lighter than air and tends to rise, which will facilitate its transport from the original emission site. Although the lethal concentration (LC) listed for ammonia (CH-217) is 2000 ppm, much smaller quantities can be harmful or annoying. Ammonia in air at levels of 0.15 to 0.25 ppm elicited complaints about odor in one Japanese study, with such subjective symptoms as headache, sore throat, eye irritation, coughing, and nausea (OG-013). Harm to grazing animals is not likely to result from ordinary fugitive losses. Dayan (DA-155) exposed calves 7.5 hours to ammonia concentrations as high as 100 ppm without observing significant changes in blood pH, pCO_2, PO_2, ammonia, and urea nitrogen, which could be related to inhalation of ammonia. The sharp odor of ammonia will also likely act as a deterrent, preventing animals from remaining long in the presence of noticeable amounts of the substance.

Trace Elements

Trace elements may be expected to leave the plant as air or water emissions. Relatively significant amounts of mercury, lead, cadmium, arsenic, and selenium are volatilized during the combustion or pyrolysis of coal (BO-109, HA-232). Mercury, lead, cadmium, arsenic and selenium removed from raw gas subsequently appear in the aqueous condensate stream. Therefore, these elements must be considered both as potential air and water pollutants. Other trace elements with important toxic properties, including beryllium, vanadium, zinc and nickel, are normally retained in ash.

In general, the wastewater streams of coal conversion facilities are expected to contain a sufficiently complex mixture of hazardous organic and inorganic substances to make zero-discharge designs desirable. The national goal of pollution discharge elimination by 1985 will also necessitate the eventual design of zero discharge for all facilities expecting to operate beyond that date. Therefore, trace elements from these sources have not been considered to be a direct threat to the quality of surface waters. The following discussion will, therefore, concern itself with trace elements as air pollutants. Although trace elements entering the biosphere as soil contaminants will, in time, enter surface and ground waters, the processes involved in this gradual diffusion are generally so slow and the amounts involved so small that there now appears to be no cause for concern that significant contamination of surface waters by trace elements will take place.

Concentrations of trace elements were measured in surface soil and sagebrush along a transection extending 53.8 kilometers (km) (86.6 miles) from the Dave Johnston Power Plant near Casper, Wyoming in the direction of the prevailing winds (KI-111). A linear relationship was found between the log of concentration and the log of downwind distance for selenium, vanadium and strontium, based on differences which were statistically significant at the 0.5 probability level. Arsenic and mercury were not analyzed; lead was included in the analysis, but showed no significant correlation with distance. Another study (KL-059) gave evidence for soil enrichment of heavy metals at a distance of several miles from a power plant on the shores of Lake Michigan.

A similar study was conducted around the Tennessee Valley Authority's (TVA) Thomas A. Allen Steam Plant at Memphis, Tennessee (BO-109, OA-006). This study noted no anomalies in soil concentrations which could be attributed to the plant along a 40-mile transection beginning 1 mile from the plant. The researchers also analyzed for trace elements in mosses, which often absorb and accumulate pollutants such as lead from the atmosphere, but they obtained a similarly negative result. Modelling of particulate fallout indicated that even with no particulate removal, a concentration factor of 1.5 would not be detected in surface soils unless the concentration of a particular trace element in fly ash was 100 times greater than that in soils. In the Memphis area, very few elements show a concentration in fly ash of more than 10 times that in soils. The study concluded that soil enrichment from particulate fallout probably would not occur more than a mile from the plant.

Several factors may play a role in the difference between the Allen Plant results (BO-109, OA-006) and those of Kieth, et al. (KI-111) and Klein and Russell (KL-059). As pointed out in BO-109, the degree of enrichment observed in the soil depends on the ratio of the concentration of a particular element in fly ash to its concentration in soil. In the alluvial sediments of the Mississippi Valley, trace elements are present in much larger concentrations than in soil typical of Michigan. Also the Michigan samples were taken beneath trees, which not only act as particulate collectors, but typically lose relatively significant amounts of absorbed materials back to the soil as leaf leachate during rainstorms. Although these considerations might permit the assumption of a large fly ash-to-soil ratio of trace element concentrations, the ranges measured downwind from the Allen Plant lie within the same order of magnitude, and often closely match those found in soil samples of the Powder River Basin taken as part of the U.S. Geological Survey (USGS) research effort (TI-029). Furthermore, the vegetation around Casper, Wyoming is principally gramagrass-needlegrass-wheatgrass prairie with very few trees, although the sagebrush sampled could share some of the same functions to a lesser degree. It is possible, too, that lower precipitation in the Powder River Basin allows trace elements from fallout to build up to a greater extent than in Tennessee.

The USGS investigators, however, included only 12 samples compared to 40 in the Oak Ridge study, some of which were split into one-inch and six-inch-deep subsamples. Although the values of selenium, vanadium and strontium measured in this study showed a statistically significant correlation with sample distance from the power plant, all values measured fell within the ranges given for the Powder River Basin as a whole (TI-029).

These three studies by themselves do not present an adequate basis for concluding whether or not fallout of fly ash from coal or oil shale processing results in trace element buildup in soil or vegetation. Each study deals with a different combination of vegetation soil and climatic regime, and uses different means of assessing and handling the data collected. None of the studies has conclusively answered the basic question. A definitive assessment of trace element hazards from this source may not be possible without reference to local conditions, and in any event must await a more rigorous investigation.

The major problem in interpreting the results of these investigations is to determine when a statistically significant trend in trace element concentrations is also biologically significant. A number of studies have addressed this problem; many have dealt with accumulator or indicator organisms from the point of view of geochemistry (SH-217, SH-218) while others have dealt with the specific toxicity and epidemiological problems of particular trace elements (HU-126, RO-209, SH-216). In some cases, it has been possible to identify the concentrations of trace elements in range plants as the causative agents in livestock poisonings, and to relate these concentrations in turn to concentrations in soils. In others, very noticeable effects on animals apparently caused by imbalances of trace elements in the diet have proved very difficult to explain because of the small quantities involved and the enormous influence of natural biological accumulation processes. An example of such an instance is given in a paper on geochemical anomalies of a clay pit area in Missouri (EB-008). Investigators were alerted to a possible geochemical problem by reports of breeding failures and poor conditions among cattle pastured in the vicinity of a worked-out pit. After extensive sampling of vegetation, soils and water, and a thorough epidemiological study of the herds involved, no single trace element was found to be responsible for the interference syndrome, nor was any single chain or pathway of accumulation isolated. Anomalously high concentrations of copper, beryllium, molybdenum and nickel were observed in both sediments and plants, as well as evidence of rapid mobility of cobalt, copper and nickel. The symptoms observed in the cattle corresponded more closely to chronic molybdenosis. From these observations, the investigator suggested that the most likely cause of the interference syndrome was an imbalance in the complex relationship between copper and molybednum, which is possibly influenced by other elements that are present in anomalous concentrations and that can, in themselves, influence metabolism of cattle. Similar syndromes have been noted in cattle from California, Florida, Nevada, Canada, Europe and Australia. In comparing these results to similar imbalances being induced by trace elements from fallout, it is worth noting that concentrations of copper and nickel in surface soils in the Powder River Basin (KI-111) fell within the same range as those recorded in the contaminated sediments near the clay pile and that vegetation levels of molybdenum were comparably high. Although molybdenum and nickel were not sampled around the Allen Station, copper values showed a similar range. These data and typical values given by Bowen (BO-165) are shown in TABLE 49.

In the absence of clearcut, repetitive patterns of uptake, accumulation and subsequent damage, a general discussion of the significance of trace element inputs needs to take into account all of the various pathways by which the elements may enter the biosphere, and the environmental conditions governing the expression of these pathways. Figure 56 is a generalized diagram of the pathways which can be important in the distributuion, accumulation, and recycling of trace elements from coal or oil shale processing.

Among the potential imports of trace elements to the biosphere, agricultural chemicals constitute a major source. Mercury-containing compounds have been very widely used as seed treatments to prevent fungal attack and to protect tubers, bulbs and corms of various kinds, and these uses have contributed large quantities of mercury to soils (GO-135). Arsenic-containing compounds, all of which are toxic, have also been used as pesticides, resulting in some very high levels of arsenic in soils (SM-106, AN-119). Cadmium is often found as a trace contaminant in fertilizers (SC-279). Trace elements added to soils by agricultural chemicals can in some places far outweigh the influence of trace elements from aerial fallout. The typical concentration of arsenic in soils reported by Bowen (BO-165), for example, was 6 parts per million (ppm); most soils contain several parts per million. A soil from New York State contaminated by calcium arsenate used for insect con-

TABLE 49. COMPARISON OF TRACE ELEMENT CONCENTRATIONS IN AN AREA OF KNOWN DAMAGE TO MISSOURI LIVESTOCK TO SIMILAR MEASUREMENTS IN OTHER SOILS

	Missouri[1]			Powder River[2]		Tennessee[3]	"Typical" Values[4]	
Element	Clay	Native Soil	Vegetation (Shrubs)	Native Soil	Vegetation	Soil Near Allen Stn.	Soils	Land Plants
Copper:								
Range	30-150	--	50-1000	3.3-67	----	15-64	2-100	----
Avg.	------	12	-------	------	----	-----	20*	14.0
Geom. Mn	------	--	-------	15	----	-----	-----	----
Molybdenum								
Range	<3-15	--	<4-20	------	3.2-17	-----	-----	----
Avg.	------	<3	-------	------	------	-----	2	0.9
Geom. Mn	------	--	-------	------	7.4	-----	-----	----
Nickel:								
Range	30-100	--	7-50	------	------	------	-----	----
Avg.	------	14	------	------	------	------	40	3.0
Geom. Mn	------	--	------	------	------	------	------	-----

References:

These values are cited as typical but not necessarily global averages.

[1] EB-008
[2] KI-111
[3] BO-109, OA-006
[4] BO-165

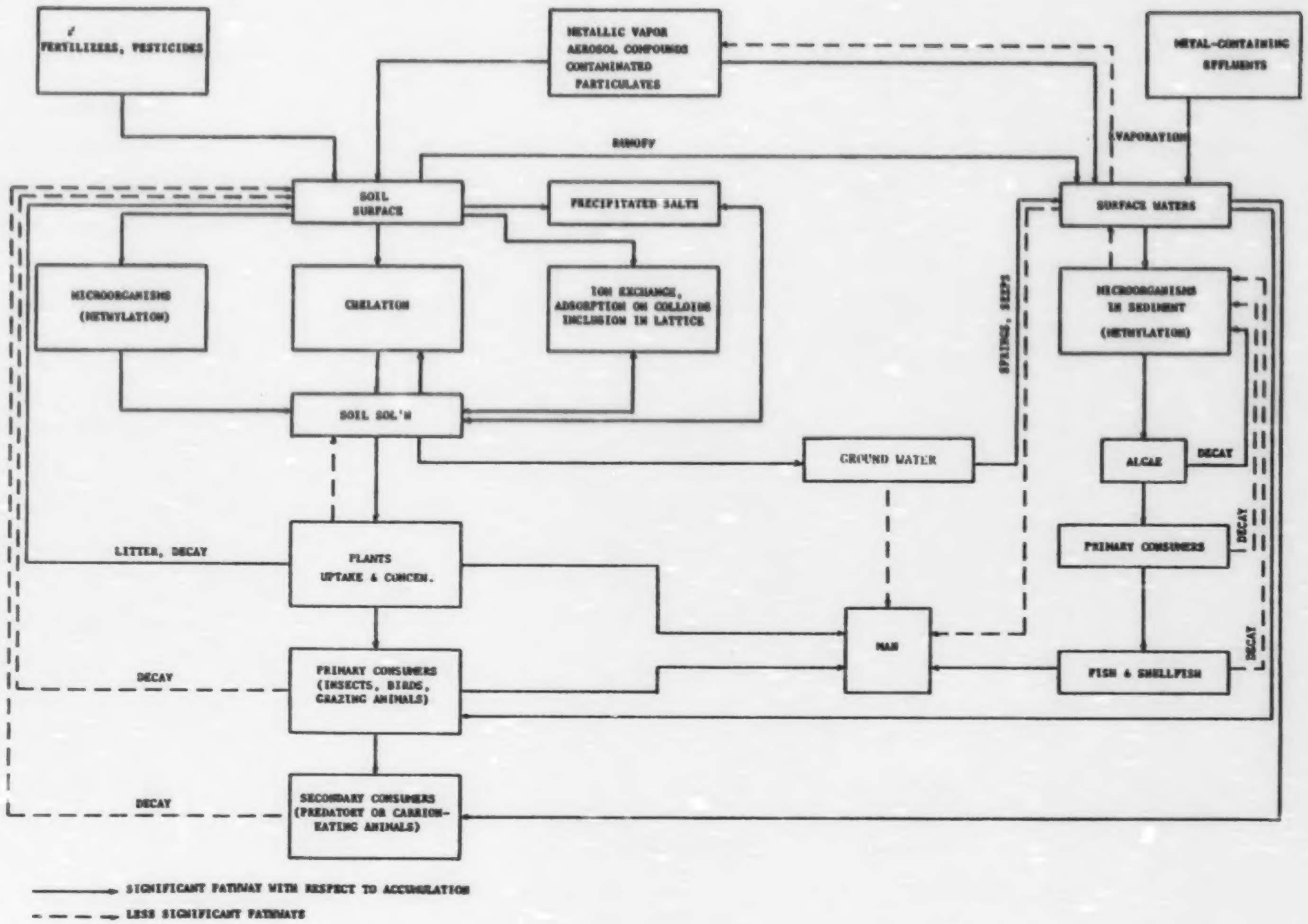
FERTILIZERS, PESTICIDES
METALLIC VAPOR
AEROSOL COMPOUNDS
CONTAMINATED
PARTICULATES
METAL-CONTAINING
EFFLUENTS
RUNOFF
VAPORATION
SOIL
SURFACE
PRECIPITATED SALTS
SURFACE WATERS
MICROORGANISMS
(METHYLATION)
CHELATION
ION EXCHANGE,
ADSORPTION ON COLLOIDS
INCLUSION IN LATTICE
SPRINGS, SEEPS
MICROORGANISMS
IN SEDIMENT
(METHYLATION)
SOIL SOL'N
GROUND WATER
ALGAE
DECAY
LITTER, DECAY
PLANTS
UPTAKE & CONCEN.
PRIMARY CONSUMERS
DECAY
MAN
DECAY
FISH & SHELLFISH
DECAY
PRIMARY CONSUMERS
(INSECTS, BIRDS,
GRAZING ANIMALS)
DECAY
SECONDARY CONSUMERS
(PREDATORY OR CARRION-
EATING ANIMALS)
SIGNIFICANT PATHWAY WITH RESPECT TO ACCUMULATION
LESS SIGNIFICANT PATHWAYS

Figure 56. Exposure pathways by which trace elements can enter the biosphere.

trol, however, had levels of up to 37 to 38 ppm (AN-119). (It is pertinent to note here that in this study, greenhouse experiments indicated that 69.5 ppm arsenic applied as arsenite were required to induce significant growth inhibition in low-bush blueberry (Vaccinium angustifolium) and that arsenic accumulation was greater in roots than in edible fruits, stems or leaves.)

Just as agricultural chemicals can dominate the trace element imports in some areas, airborne contaminants other than those released in coal pyrolysis can also locally raise background levels to a point where inputs from coal would be obscured by a very low ratio of concentrations in fly ash to soil levels. Smelters have been, at least in the past, well-known sources of trace elements in harmful concentrations (e.g., OY-002, BI-068). It has been shown that in areas with significant aerial contamination, plants may absorb a significant proportion of their total cadmium burden from the air (LA-198). Kitamura (cited in FR-163) measured cadmium deposition within 500 meters (m) from a smelter at 6.2 mg/m^2/month over a six-month period. Lead aerosols are also accumulated by the waxy cuticles of many plant leaves (AR-062). The trace metal content of trees is apt to be a function of aerial composition (WA-208).

Once in the soil or deposited upon its surface, the fate of most trace elements is very poorly known. The factors governing uptake and accumulation in vegetation, and the natural cycling or dissipation of trace elements, lie at the heart of any attempts to understand the significance of their accidental introduction into the biosphere. The complexities of the interactions of these factors, however, present a formidable task to the investigator. Most research has dealt with the dynamics of relatively simple laboratory and experimental systems often focused on only one trace element. Most of the factors which in nature will vary simultaneously are held constant to allow the experimenter to observe the responses of the system to a single one. Much of this work, as related to agricultural applications, has been reviewed by several authors in a compendium edited by Mortvedt, et al. (MO-173). It is possible to discuss qualitatively the various major soil and plant processes which govern the movements of trace elements, as well as the environmental parameters influencing them. Attempts to predict their relative significance in specific situations, however, must rely largely on expert judgment rather than on modeling or calculation.

The mechanisms of many observed phenomena, particularly those of the interference of one trace element with the uptake and translocation of another in plants, are far from being adequately demonstrated or agreed upon in theory by investigators. In the absence of many connecting links, anything approaching a generalized theory of trace element movement cannot be attempted. Furthermore, the wide range of phenomena observed by different authors points strongly to the dominant role of plant species and local geochemistry in determining the fate of trace elements introduced into soil/plant systems.

A thorough and detailed discussion of what is now known, from various sources, about trace elements in soil/plant systems and their significance in human or other food chains, has not yet been published, to our knowledge. Such a compendium, directed at interpreting the relative significance of trace element inputs by man, would be a very useful tool, not only in evaluating the potential for pollution problems from the new coal processing technologies, but in providing clearcut guidelines enabling the design of further research to fit into and extend an existing framework of knowledge bearing on critical processes.

The moisture in the soil is the key to most of these processes since it provides the medium by which materials can enter, move within the system and leave through leaching or plant uptake. Equilibria between the solid and aqueous phases of the soil also govern the degree to which materials can be immobilized in the soil as solid precipitates, absorbed onto colloidal particles by ion exchange, or altered in chemical form, such as by chelation with organic molecules (LI-123). Biological mediation, particularly by bacteria, can enter into many of these processes.

The availability of trace elements in soils may be influenced by a number of variables. Perhaps the greatest influence will be the physical structure of the soil itself. Soil texture and organic matter content not only affect permeability and infiltration rate; they also determine the quantity of ions such as calcium cations (Ca^{+2}), phosphate (PO_4^{-3}), and zinc cations (Zn^{+2}) which can be held by the soil and the degree and the rate at which they may become mobile in the soil moisture.

Trace elements tend to be absorbed and immobilized by most soils. Numerous studies have shown that only small amounts of the boron, arsenic, nickel, cobalt, cadmium, zinc, antimony, silver and mercury absorbed by soils from polluted air in urban and industrial areas is actually available to plants (KA-194, LA-196, LA-197, PA-185, RO-130). Uptake and accumulation in aerial plant parts are reduced by ion inactivation through inorganic and organic equilibria, accumulation at the soil surface above the root zone, and by exclusion at the root surface or immobilization in roots themselves (BO-163). The degree to which different metallic ions are inactivated in soils varies considerably between reports, but soils appear to be more effective in removing Cu>Pb>Zn>Cd>Ni (SH-218). Alkaline soils appear to be more effective in removing copper, zinc, and lead than acid soils (BO-164, JO-157), although liming does not affect cadmium contents of plants (JO-156). Bohn (BO-163), reviewing the subject of soil absorption of air pollutants, states that "except in circumstances of protracted and heavy fallout near smelters and other industrial sources of air pollutions, the accumulation of heavy metal in soils from air pollution probably does not lead to plant concentrations of these ions which are hazardous to the plants, grazing animals, or man."

The subject is not quite closed, however, by such a general statement. Direct toxicity by trace metals is only the acute expression of trace element pollution; imbalances are basically a nutritional problem and may occur because of very small changes in the chemical composition of soils and plants. Because these chronic, synergistic effects exist, and are as yet so poorly accounted for, it is necessary also to look at processes going on in the soils after a trace element has been absorbed and what can cause it to be remobilized. Although in the short run contaminants may seem to disappear into soils, they are not lost from the system but are held immobile by complex chemical equilibria which respond to changes in their activity in soil solution. The significance of these equilibria in the continual availability of ions to plants which are removing them from soil solution and recycling them, should be readily apparent.

The availability of trace ions in the soil is mediated principally by three types of interactions: formation of very slightly soluble inorganic salts, adsorption onto soil colloids, and chelation or complexation with organic matter. Many metal cations will occupy exchange sites only until precipitation reactions occur which reduce their activity in soil solution. When this happens, they are drawn off into the soil solution, precipitate as insoluble salts, and are replaced at the exchange sites by more common cations such as calcium, manganese, sodium or potassium. These metals may eventually find their way into the lattice structures of crystalline minerals (LI-123). Metals tend to be more available in acid soils; their activities may decrease as much as a hundredfold for each unit increase in pH.

Chelation or complexation with organic matter, however, may enhance the availability of metals by preventing their precipitation while at the same time holding them in a form from which they may be more easily released (LA-199, NO-063). Field and experimental data have shown that the distribution of ionic mercury in soils is controlled largely by humus; humus-rich portions of soils sorb up to twice as much mercury as clay-rich portions (TR-068). Humic and fulvic acids have strong mercury-binding properties, which retard leaching (GO-135). Biological action can also increase the availability of certain trace metals by converting them to soluble organic forms. Arsenic, mercury and selenium all have a tendency toward biologic methylation (HA-232) which can be carried out by a variety of microorganisms. Jernelov (JE-046) reports that methylation in aquatic sediments can be related directly to general microbial activity, and hence to conditions favoring the growth of various bacteria and fungi. Although methylation can occur in both aerobic and anaerobic systems, rates of methylation are higher under aerobic conditions. In nature, anaerobic conditions will tend to cause the formation of insoluble sulfide through reaction with hydrogen sulfide (H_2S).

All those factors which govern the amount of a given substance in the soil solution, such as pH, quantity and kind of organic matter, and cation exchange capacity, affect its uptake. Other ions present in the soil may also influence the amounts absorbed by plants. For example, soils with large amounts of available phosphate often produce, by a poorly understood mechanism, crops which are deficient in zinc, and similarly interfere with the uptake of other metallic ions such as iron, copper, and nickel. Nitrogen and sulfur can have similar effects. Interactions of a more complex nature may also take place among ions during and after uptake; zinc is known to interact with both cadmium and copper in this way. This subject has been reviewed in detail by Olson (OL-034). Soil moisture and aeration may also influence the uptake of materials by plants. Rooting depth, especially in soils where ions are distributed in distinct horizons, can also influence uptake and accumulation, especially as the plants grow and their roots extend deeper.

Once within the plant, some substances are more easily accumulated than others; in acid soils, for example cadmium is easily transported to plant tops. Metals may also accumulate to varying levels in different parts of the same plant -- roots often retain relatively large quantities of heavy metals while fruits and grains may accumulate comparatively little. The age of the plant and the time of year may also influence accumulation. Different species of plants exhibit different accumulation patterns, and variations between varieties of the same species can be as great as those among species.

The decomposition of crop residues leads to the liberation of significant amounts of trace elements (LA-199). Microbial activity tends to promote chelation of metal ions, while newly formed humic substances can act as solubilizers. Soil organic matter tends to form highly mobile complexes with metals which may account for the greater part of the metals available in the soil profile. In this way, trace metals may accumulate and recycle in the terrestrial environment, especially because deep-rooted plants tend to take up ions which have leached into the lower layers of the soils and redeposit them on the soil surface as litter.

The above discussion of the fate of trace metals from air pollution in the terrestrial ecosystem illustrates some of the complexities governing this interaction. Although information at all levels is vitally needed, certain areas are particularly crucial to understanding the mechanisms by which trace elements from air pollution can affect the biosphere. This information will, in turn, determine the extent to which particular trace element species should be monitored on a long-term basis. These may be summarized as follows:

(1) The potential significance of trace element deposition has not been established. Studies of deposition around power plants have produced conflicting views of the likelihood of trace element enrichment from fallout. It is clear, however, that concentrations in both soil and vegetation have a strong influence on the detection of significant increases in different geographical area. Monitoring the deposition rates of trace elements from coal or oil shale processing would aid in assessing the risk of contamination of various soils, and would allow comparisons to be made with documented cases of industrial metal contamination for which such data are available. Future research could profitably investigate, using mathematical models together with field monitoring, the ratios of concentrations in fly ash to concentrations in soils which must be achieved before significant soil enrichment may take place in those geographic areas most likely to be affected by the development of coal conversion technology. Data indicate that trace elements may not be released by coal processing in sufficient quantities to produce significant increases in concentrations in many soils. This needs to be verified, especially in the areas to be affected.

(2) The relationship between small increases of trace element concentrations and the development of nutritional problems in livestock needs to be better understood. Data available

on the toxicity of individual elements indicate that, in general, the soil concentrations required to produce immediate toxic responses in plants and animals are much higher than those found in normal soils. The likelihood of trace elements emitted by coal conversion processes enriching soil to these levels seems less than that of contamination by agricultural chemicals or ore sintering and smelting. This does not rule out the possibility of chronic nutritional imbalances resulting from very small changes in the trace element balance of soils. As a first step, documented cases of such imbalances, like the one cited above, should be reviewed. Also, the plant and trace element concentrations implicated in the imbalances should be compared with existing baseline data for areas such as the Powder River Basin.

(3) Indicator plants, known to accumulate trace elements, should be reviewed for possible use in long-term monitoring. The influence of such environmental conditions as moisture, temperature and season on the uptake and accumulation of trace elements should be well understood both for plants to be used as indicators and for accumulator plants which may become problems because of their consumption by livestock.

(4) The synergistic effects of trace elements in producing chronic damage to vegetation, especially through interference phenomena affecting uptake, need to be evaluated with special reference to the likelihood of fallout from coal conversion processes contributing to the development of such problems on marginal soils. Special attention should be given to range plants and crops grown in areas most likely to be affected.

(5) The contribution of trace elements from coal and oil shale industries is relative to that which may be produced by increased automobile traffic, associated industry, etc., which are likely to accompany regional development and should be carefully examined. It is the cumulative impacts of resource exploitation which will actually be felt by a region's biota; evaluating the influence of basic industry alone does not present a complete picture.

Trace Organics

A number of potentially hazardous organic substances are produced in coal gasification and liquefaction processes and in oil shale retorting, and a portion of these materials will end up in the waste streams. The primary hazard arising from the production of organic wastes is from their disposal in evaporation ponds for contaminated wastewater streams.

As explained earlier, pathways by which these substances may enter the biosphere depend largely on site-specific and design-specific factors. It is likely that direct contamination of surface waters through leakage or overflow will be strictly controlled. The following discussion will be oriented principally around the risks of contact or accidental ingestion by terrestrial organisms of substances in fairly concentrated form, rather than the effects of low-level contaminants on aquatic communities. It is possible, of course, that some aquatic organisms, particularly highly tolerant algae and invertebrates, could survive in wastewater evaporation ponds if the ponds are sufficiently dilute. This depends, however, on so many unknown factors of design and wastewater chemistry that speculation is fruitless. Therefore, the entire question of colonization of evaporation ponds by organisms other than bacteria and fungi has not been considered.

Exposure to a broad variety of chemical agents has been shown to result in cancer in laboratory animals and has been implicated in human cancers; more chemicals are suspected of having carcinogenic or mutagenic properties. The majority of these are small molecules with molecular weights of less than 500, whose carcinogenicity is thought to be related to their electrophilic properties (MI-181). These include simple alkylating agents, aromatic amines and amides, aliphatic nitrosamines and nitrosamides, aza-arenes, halogenated aliphatic and alicyclic hydrocarbons, complex pyrrolizidine alkaloids and many polycyclic aromatic hydrocarbons. In addition, compounds of beryllium, cadmium, chromium, cobalt, lead, nickel and selenium have been identified or are suspected of being carinogens (CL-067, MI-180, SH-219). Some trivalent arsenic compounds have also been implicated in the induction of skin cancer and possibly in other organs through prolonged contact, but experimental evidence fails to support this view (AN-120). Most authors agree that the most potentially dangerous compounds are the polycyclic aromatics, of which the benyopyrenes are especially potent and well documented (HO-222).

Much of the literature of chemical carcinogenesis deals with uptake by respiration, particularly products of incomplete combustion of organic materials such as gasoline and tobacco. Ingestion and direct contact of carcinogens with the skin, however, have also been strongly implicated in cancers of laboratory animals and man (HE-152, LI-122, MA-455, WO-062). A large number of agents must be metabolized before their carcinogenetic properties, actually the properties of metabolic derivatives, are expressed (MI-181). The role of the environment is being increasingly recognized as one of the major factors in the etiology of cancer. Environmental factors may be important causative agents in some 80% to 90% of human cancers (HI-131).

The process of carcinogenesis is not simple. The carcinogen need not be continuously present for tumor formation to result. A long latent period frequently ensues, the length of which is related to the original dose. Sufficiently large doses of polycyclic aromatics will induce the complete carcinogenic process in mouse skin in a matter of months; very low doses will initiate the early stages of the process, but the rate at which it proceeds will be so slow as to make it impossible to complete during the mouse's normal lifetime (HE-152). Prolonged exposure or higher dose rates will also increase frequency of tumor-bearing animals in an experimental population as well as the total number of tumors (DR-045, MI-181). Combinations of strong carcinogens with other, weaker carcinogens can either increase or reduce the potency of the strong carcinogen (FA-112). Other chemicals, which are themselves not carcinogens, may be involved in completing the process initiated by carcinogens as tumor promoters. Although the initiation stage is essentially irreversible and rapidly completed, promotion is apparently reversible, and takes place over a much longer period (MI-181). A third group of compounds, including N-alkylated indoles and carbazoles, can enhance the activity of known carcinogens if applied simultaneously, although they do not initiate carcinogenesis themselves. These apparently inhibit the natural detoxification of carcinogens by the organism (HO-222, WY-008). Many factors, including dose, frequency, route of administration, species, sex, age, hormonal status, viral infection and intrinsic species susceptibility govern the rate at which chemically induced tumors appear in a population.

In addition to their presence in evaporation ponds, organics such as polycyclic aromatics (PAH) may disperse directly into the environment from industrial installations. The potent carcinogen, benz (a) pyrene, was found to be present in soils around an oil refinery in concentrations more than 60 times that in the soils of surrounding residential and farming areas (SH-215). The significance of soil contamination by polycyclic aromatics, however, must be evaluated in the light of natural processes involving these compounds. Mallet (MA-456) found considerable amounts of PAH in terrestrial vegetation and this was originally thought to be the result of air pollution. It is now known, however, that bacteria, algae and higher plants manufacture PAH (GR-178, MA-457, BO-109). Some aerobic soil bacteria degrade PAH, as well. It, therefore, appears that, at least in the soil/plant system, a natural equilibrium probably exists between the production and degradation of PAH. It has been stated that the slightest change in molecular configuration renders carcinogenic PAH inactive. This statement might be tempered with the Millers' concept (MI-181) of carcinogenicity that changes in configuration render the molecule less electrophilic and reduces its carcinogenicity. In any event, although some PAH can induce cancer, by no means do all of them, and PAH breakdown by soil bacteria undoubtedly converts many molecules with carcinogenic properties to harmless or less potent forms.

In addition to carcinogens, organic compounds may exist or be formed in evaporation ponds used to contain wastes which are themselves toxic or irritating. The most prominent of these may be phenols, which have demonstrated dermal toxicity when dissolved in water (CO-323), as well as being toxic when inhaled or ingested. Some phenols and related compounds are known to be potent plant growth and germination inhibitors (RI-092).

An important aspect of assessing potential problems resulting from the disposal of hazardous organics concerns their breakdown in the environment. Virtually all hydrocarbons of the aliphatic, olefinic, aromatic or naphthenic series may be oxidized by microbes if properly dispersed (ZO-011). Molecular structure, however, determines the ease with which these oxidations are accomplished. In general, aliphatic compounds are oxidized most rapidly, with long-chain molecules attacked more readily, within limits, than short chains. Cycloalkanes, aromatic and naphthenic compounds are more resistant to oxidation (DU-091, MC-178, OO-002). Isoalkanes are highly recalcitrant, and alkanes with multiple methyl branches, methyl branches too close to the end of the chain, or with branches larger than methyl groups are not attacked (DU-091).

A reliable prediction of what hazards may arise from the disposal of organic contaminants in large evaporation ponds will have to await the availability of such wastes themselves from pilot projects or commercial operations. Until such time as actual disposal situations can be studied, a number of basic topics need to be investigated so that a basis will exist for predicting and dealing with the effects of disposal. Areas which could be profitably studied include the following:

(1) The extent to which known carcinogens, particularly PAH, are attenuated in soils should be investigated with special reference to such factors as temperature, pH, organic matter, and moisture and aeration which may mediate the process.

(2) The possibility of using bacteria as agents to degrade organics, especially PAH, in coal-conversion wastewaters, should be investigated. A large amount of literature (NE-080) exists on the use of microorganisms to degrade spilled petroleum under both aerobic and anaerobic conditions. A mixed culture of soil and activated sludge organisms has been used to remove phenol by bio-oxidation. However, in a recent study (ST-299) a population of aerobic bacteria present in the waters of a tip-lagoon system being used to purify a coke-oven effluent was shown to play a very doubtful role in the process. This was thought to be related to a deficiency of orthophosphate and to poor aeration. It may, therefore, be worth considering the possibility of innoculating waste ponds with specially tailored bacteria, or adding materials to the waste mix which may promote bacterial growth. Techniques used in sewage treatment processes should be investigated for their applicability to coal-conversion wastes. The large amounts of trace metals which may be present in wastewaters may tend to inhibit bacterial growth; this factor should be examined.

When waste streams become available for experimentation, a number of very useful studies could be performed, including the following:

(1) The ability of mixed wastes, concentrated as they might be in an evaportion pond, to support the growth of noxious or disease-causing organisms such as Clostridium botulinum, should be investigated.

(2) The ability of mixed wastes to cause cancer from exposure by contact should also be examined and related to the tendency of wastes to concentrate over a period of time.

(3) Bottom sludges from evaporation ponds should be tested for carcinogenicity and evaluated in light of the need for handling and ultimately for disposal as solid waste.

(4) The possibility of the formation of toxic gases or the evaporation of harmful materials from the surfaces of evaporation ponds should also be investigated. The presence of metals as potential catalysts and of microorganisms as biological mediators should be kept in mind in designing experiments or in monitoring the conditions under which toxins could be released into the air. These studies should be oriented toward the use of ponds by wildlife, especially waterfowl, and the occupational health of workers.

Bacteria in the Detection and Treatment of Acid Mine Drainage

A potential water pollution problem which can arise indirectly from the development of coal conversion processes is the acidification of streams by mine drainage. The principal cause of the low pH of mine drainage waters is the oxidation of pyrite (FeS_2). The fact that autotrophic bacteria of the *Thiobacillus*-*Ferrobacillus* group can only grow by utilizing reduced iron and sulfur compounds makes it possible, in theory, to use them in monitoring the rate of pyrite oxidation in a mine. Dugan (DU-091) discusses experiments in which the rate of oxidation of iron by bacteria in continuous culture was related to the rate of cell production. Since a mine with a constant throughput of water carrying bacterial cells away from the site of their production behaves, in many ways, like a continuous culture experiment, it should be possible to calculate, knowing the efficiency of the bacterial energy conversion step to be between 10% and 30%, the flow rate of water out of the mine or its refuse dumps, and the concentration of bacterial cells within the outflow waters, how much pyrite is being oxidized per unit time.

It may also be possible to use another set of bacteria, the heterotrophic *Desulfovibrio*-*Desulfotomaculum* group, which reduces sulfates, in the treatment of acid mine drainage problems (DU-091, TU-037). These anaerobic bacteria require a redox potential of -150 to -200 millivolt and a source of organic matter. Conventional designs for anaerobic sewage digestion systems could be adapted to this application using sawdust, wood chips, wastepaper or waste vegetable matter as an organic base (DU-091). Although antimicrobial agents have been shown to be an effective means of handling iron and sulfur-oxidizing bacteria in the laboratory, they may not be as well suited to use in abandoned drift mines (TU-037).

Most of the coals being considered for large-scale conversion projects are located in the Western States, where the low-pyrite content of the coals and the generally alkaline surrounding strata prevent the development of acid mine drainage problems. To the extent that eastern coals, particularly in Kentucky and Pennsylvania are involved (HA-369), however, the development of a biological treatment system may be worth pursuing.

Summary of Potential Biological Impacts

A great many factors which may be expected to influence the biological impacts of coal conversion plants cannot be determined at this time. Nevertheless, certain general conclusions may be drawn regarding the likelihood and probable significance of such impacts as can be envisioned at this time. In addition, certain gaps in our knowledge may be identified in which further research is needed before impacts may be monitored, predicted or controlled. These may be summarized as follows:

(1) Among criteria air pollutants, there is some evidence, albeit somewhat inconclusive, that health effects are more closely related to the combined and synergistic effects of aerosols, fine particulates (especially deliquescent salts) and atmospheric sulfates than to sulfur dioxide alone. Similarly, ecological stress from general air pollution may be in some areas largely the result of acid rainfall, resulting from the rainout of atmospheric sulfates. Coal conversion plants and other coal-burning industries will be developing, if current trends continue, around the coal fields. Therefore, the potential exists for significant increases in airborne sulfates and particulates from many new sources in a given airshed. It is suggested that sulfates, fine particulate matter and aerosols, none of which is currently governed by regulation, be monitored over relatively large areas as development proceeds, and correlated with any changes in frequency of respiratory diseases or related health problems. Further study on the basic nature of the relationship of sulfates and aerosols/particulates to health is also needed both to interpret subsequent measurements in the developing coal regions and to determine what levels may be considered acceptable for these contaminants.

Regular long-term monitoring of changes of the pH of rainfall and of soils will also be informative when compared to concurrent measures of atmospheric sulfate levels. Serious acid rain problems have usually been associated with very heavy sulfur emitters of a much larger size than can presently be envisioned for the coal regions of the U.S. Given present regulatory constraints on sulfur dioxide emissions and ambient levels, it does not appear likely that a significant problem with acid rain will develop in these regions.

(2) Intermittent emissions of H_2S, HCN and NH_3 will occur in the plant as part of the process of coal pyrolysis. These losses will be largely fugitive and will be mainly confined to the plant site. There is a chance that some odor may be noticeable, depending

on the location of the plant with respect to occupied dwellings, but in general these gases are not considered to pose a serious potential environmental problem except for occupational exposure within the plant itself.

(3) Trace metals, of which the most significant will probably be lead, mercury, cadmium, arsenic and selenium, will be present in both air emissions and process wastewaters. Other trace elements, including nickel, beryllium and zinc, will largely remain in the ash. Recent studies have presented evidence that the migration of these elements away from storage ponds will not pose a serious problem because of the ease with which they are attenuated by soil. It has, therefore, been assumed that the same applies to ash disposed in depleted strip mines and that these elements may be effectively contained. Similarly, the movement of trace elements from wastewater impoundments is not considered a serious problem, and it is assumed that such ponds can be designed as to effectively prevent excessive seepage or accidental overflow. Therefore, trace elements were treated in this report principally as air pollutants.

No definitive study of the significance of trace emissions from coal-burning plants exists; reports differ in their interpretation of the likelihood of soil contamination from this source. Little attempt has been made to determine the biological significance of such contamination as can be predicted or observed. In general, it appears that soil levels required to promote acute intoxication in plants or animals are unlikely to result from such emissions, and that such problems as may reasonably be suspected of being related to this source may be more in the nature of chronic micronutrient imbalances affecting livestock metabolism.

It is suggested that further research be directed toward a better definition (through rigorous field studies coupled with mathematical modeling of particulate fallout) of the parameters governing the deposition of trace elements on soils. This is needed first to assess the actual likelihood of soil contamination and then to compare expected levels to those which have been related to livestock problems in the past. The synergistic effects of trace micronutrients, especially as related to interference of one element in the uptake of another, need also to be better understood as they affect the growth of both plants and animals. An effort should also be made to identify and calibrate indicator species of plants, whose tendency to respond to trace element increases, may be applied to long-term environmental monitoring. Finally, it was emphasized that trace element emissions expected from other sources, such as gasoline combustion which will increase should be considered in assessing the overall likelihood of trace element contamination.

(4) Organic by-products of coal and oil shale processes will enter the environment principally as process wastewaters impounded on the site and as fugitive losses. These waste ponds will contain a mixture of hydrocarbons, ammonia, phenols, hydrogen sulfide and trace elements. exact composition, however, cannot be predicted on the basis of the present level of process development, and will depend in any case upon wastewater treatment methods employed. Such wastewaters which may be impounded, however, may be expected to be moderately to highly toxic. In addition, bottom sludges formed in these ponds present ultimate problems of solid waste disposal.

Several lines of inquiry are suggested recognizing that some will have to await actual commercial development of coal conversion facilities and the chance to observe actual waste disposal situations. These include the investigation of the ability of soils to filter or attenuate known organic carcinogens. The use of bacteria or other microorganisms to degrade the hydrocarbon content of wastes should also be investigated. A strong base for such an effort exists in prior work on activated sludge treatment of municipal wastes and in tailored bacteria used for the control of petroleum. When actual wastes become available for experimentation, the carcinogenic properties of both wastewaters and bottom sludges can be ascertained. Volatile substances or evolved gases which may be present at the surface of evaporation ponds may harm waterfowl and should also be examined. Finally, the ability of impounded wastes to promote the growth of noxious or pathogenic microorganisms should be tested.

Because of our present lack of knowledge regarding the compostion and properties of wastewaters from coal conversion, an attempt to assess their environmental impact is largely speculative. This and the fact that known carcinogens will be among the waste products argue for placing a high priority on research in this area.

(5) Although most plans for gasification or liquefaction of coal involve western coal resources, several have also been proposed which will use coals from Kentucky and Pennsylvania. The high pyrite content of these coals and the surrounding strata make acid mine drainage a serious problem. Bacterial counts may be used to

monitor the rate of pyrite oxidation. Also, the adaptation of an anaerobic treatment system using another group of reducing bacteria shows some promise as a means of lowering the acidity of mine waters. Further pursuit of the possibility of using bacteria both to monitor and control acid mine drainage is recommended.

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APPENDIX A

APPENDIX A

TABLE OF CONVERSION UNITS

To Convert From	To	Multiply By
Btu	Kilogram - Calories	0.25198
Btu/pound	Kilogram - Calories/Kilogram	0.55552
Cubic feet/day	Cubic meters/day	0.028317
Feet	Meters	0.30480
Gallons/minute	Cubic meters/minute	0.0037854
Inches	Centimeters	2.5400
Pounds	Kilograms	0.45359
Pounds/Btu	Kilograms/calorie-kg	1.8001
Pounds/hour	Kilograms/hour	0.45359
Pounds/square inch	Kilograms/square centimeter	0.070307
Tons (short)	Metric tons	0.90719
Short Tons/day	Metric tons/day	0.90719

APPENDIX B

APPENDIX B

ABBREVIATIONS

AGA	American Gas Association
°API	American Petroleum Institute symbol fo inverse of specific gravity
ave	average
bbl	barrel
BCD	barrels per calendar day
BOD	biological oxygen demand
Btu	British thermal unit
Btu/lb	Btu per pound
Btu/scf	Btu per standard cubic foot
COED	Char Oil Energy Development
COD	Chemical Oxygen Demand
CSF	Consol Synthetic Fuel
ft^3	cubic foot
ft/sec	feet per second
geom. mn.	geometric mean
gpm	gallons per minute
g/scf	grams per standard cubic foot
IGT	Institute of Gas Technology
lb/day	pounds per day
LPG	liquid petroleum gas
mg/l	milligrams per liter
MM	million
OCR	Office of Coal Research
PAH	polynuclear aromatic hydrocarbons
POM	polynuclear organic material
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
psia	pounds per square inch, atmospheric
psig	pounds per square inch, gage
ROM	run-of-mine
scf	standard cubic foot
sft^3	standard cubic foot
SNG	substitute natural gas
SRC	solvent refined coal
SUS	Seybolt Universal unit for viscosity
TOC	total organic carbon
TOSCO	The Oil Shale Corporation
wt-pct.	weight percent

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